THE FUTURE OF THE NATION'S ENERGY UTILITIES: IMPLICATIONS FOR FEDERAL R.D.&D.

HEARINGS

BEFORE THE

SUBCOMMITTEE ON
ENERGY DEVELOPMENT AND APPLICATIONS

OF THE

COMMITTEE ON
SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES

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*On assignment to Budget Committee for 97th Congress.

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THE FUTURE OF THE NATION'S ENERGY UTILITIES: IMPLICATIONS FOR FEDERAL R.D. & D.

TUESDAY, JUNE 23, 1981

House of Representatives,
Committee on Science and Technology,
Subcommittee on Energy Development and Applications,
Washington, D.C.

The subcommittee met at 9:36 a.m., in room 2318, Rayburn House Office Building, Hon. Don Fuqua presiding.

Present: Representatives Fuqua, Wolpe, Ertel, Winn, Sensenbrenner, Weber, Gregg, McGrath, Dunn, and Walker.

Staff present: Martha Krebs, staff director, Eugene Frankel, science consultant and Daniel Steinway, minority counsel.

Mr. Fuqua. Today we address an issue of great importance for our Nation's energy policy—and especially for the future of its energy research, development, and demonstration programs.

The Energy Development and Applications Subcommittee has a special concern about the future of the Nation's energy utilities. We count on those utilities to purchase and use many of the technologies that we authorize in the DOE budget. These include fuel cells, MHD, advanced coal combustion systems, windmills, OTEC plants, solar thermal power systems, and geothermal plants. On the full committee level we can add to that list advanced fission and fusion reactors.

We also expect the utilities to back up and buy back the energy produced by photovoltaics, cogenerators, heat pumps, and low head hydro systems. Thus, we have a vital stake in the strategies that are adopted by utilities and their regulators for meeting the industry's problems and in the success or failure of those strategies.

If utilities continue to experience poor profitability and a shortage of capital, they may simply be unable to commercialize the technologies being developed by DOE. If, on the other hand, they diversify into full service energy companies, they may speed the market penetration of on-site energy conservation and solar heating and cooling devices.

If the rules for cogeneration and small power production are modified to encourage greater utility involvement, we could see a boom in windmills, photovoltaics, and small-scale hydroelectric systems. If the entire electric generating industry is deregulated and separated off from transmission and distribution, there could be an entirely new generating mix.

It is to explore these possible trends and their consequences for energy R. & D. that the subcommittee has called this hearing today.

The subcommittee is not involved in utility regulation nor with the intricacies of PURPA or the Fuel Use Act. One of our members, the former chairman of this subcommittee, my distinguished colleague from New York, Dick Ottinger, is in fact the focal point for all utility regulatory activities in the House in his role as chairman of the Energy Conservation and Power Subcommittee of the House Energy and Commerce Committee. We owe him a debt of gratitude for first sensitizing the subcommittee to the importance of utility issues at his excellent workshop on "Utilities and Energy Conservation" last September.

The utilities' current financial situation and their ability to develop and utilize new technologies must be understood by the subcommittee if we are to make intelligent decisions about the DOE budget. Thus, I am pleased to greet the experts who have agreed to testify before us, and to learn what they think about the future of the Nation's energy utilities.

Our first witness will be Mr. Charles Benore, vice president of Paine, Webber, Mitchell & Hutchins of New York.

And I would like to invite the others, Mr. Terry Ferrar, vice president, regulatory programs, Edison Electric Institute, and Mr. David Roe, Environmental Defense Fund of California.

Mr. Benore, we will be happy to hear from you.

STATEMENT OF CHARLES BENORE, VICE PRESIDENT, PAINE, WEBBER, MITCHELL & HUTCHINS, NEW YORK, N.Y.; DAVID ROE, ENVIRONMENTAL DEFENSE FUND, BERKELEY, CALIF.; AND TERRY FERRAR, VICE PRESIDENT, REGULATORY PROGRAMS, EDISON ELECTRIC INSTITUTE, WASHINGTON, D.C.

Mr. BENORE. Thank you.

Good morning. I thank you for the opportunity to talk with you about the financial status of the electric power industry.

Electric utility common stocks are at this time trading at about one-half of their 1965 value, and in 1965 dollars of constant purchasing power about one-fifth, or 20 cents on each dollar. Clearly, the electric power industry has been a bitter disappointment to investors.

One does not have to look too far to find the problem. Profitability and its quality in this industry have been below that of virtually all other industries. The return on equity, for example, over the 1970-80 decade has remained at about 11 percent, while the profitability of this industry's major competitors for common stock equity capital or industrial companies, has risen from about 10 percent in 1970 to nearly 17 percent in 1979, and about 15 percent in the recession year of 1980.

Other than inadequate profitability, there is another problem. That is the quality of the profits of the electric power industry are very much lower than its principal competitors in the marketplace. Electric power companies with long investment lead times and capital intensive projects, accrue substantial amounts of allowance for funds during construction credits. AFUDC, in fact, accounted for 55 percent of 1980 earnings per share. Investors are averse to AFUDC earnings because cash in hand is more valuable than the promise of cash, or an IOU, in the uncertain future.

All of this has occurred because the arithmetic of producing electric power has changed. This is no longer a declining-cost industry but is now an increasing-cost industry. The arithmetic of the business has changed because of the following factors:

First, the cost of generating plant per kilowatt has substantially increased. It used to be $100 or $200 per kilowatt. It is now in the area of $1,400 to $1,500 per kilowatt.

Second, larger investments of a nonrevenue producing nature to meet regulatory and environmental requirements to construct and operate an electric power system are now present.

Third, inflation, as we all know, has increased, which has caused costs, including capital costs, to rise at a rapid rate.

Fourth, sales and revenue growth has dramatically slowed while cost growth has accelerated.

And, fifth, companies have not been able to sufficiently reduce costs or increase revenues in response to these changes and to attain a satisfactory level of financial integrity and to make their securities relatively attractive to investors.

As one examines the problems of this industry, one might think it has managerial problems. I wonder, however, how poor management could be so widespread.

Moreover, most management audits are favorable. I believe that the principal problem is the lack of adequate rate relief to cover the costs of providing electric power service including capital costs.

Let me give you a couple of examples, if I may. The return on equity is about 11 percent currently. It is lower than the cost of capital to the U.S. Government which currently for long-term bonds is about 12¼ percent. I submit that there is more risk in the common stock securities of the electric power industry, and that this is an untenable and absurd condition and one which threatens to ruin the electric power industry as we know it today unless it is corrected.

Another problem electric companies have is they don't earn the returns that regulators consider to be fair. The typical allowed return for electric companies in 1980 was 14.3 percent. They earned 10.7 percent or only about 75 percent of the allowed return, which was considered fair by regulation. This is a grave inequity and one that threatens the credibility of regulation with investors.

Another problem that I think reflects the unfavorable position of the electric power industry is the continued sale of common stock below book value, which has the very undesirable effect of confiscating or taking away the investment of investors in these companies and the return on this investment.

These are three measures of the untenable position that this industry finds itself in today with the investment community.

Reflecting this unfortunate circumstance, it is not surprising that electric power companies are having trouble in raising capital. Over the last 12 months, through April 1981, about one-half of bond financing by the electric power industry had a term of 10 years or less. Investors are no longer willing, in part because of very high rates of inflation, to give this industry money with a 30-year term.

In addition to that, in 3 months of 1980, the electric power industry came to the market for common equity capital and went away with less than 75 percent of what it had sought at the beginning of the month.

It really boils down, from an investor perspective, to an inability to make money in electric utility common stocks. Over the last 15 years these stocks have gone up in only four of those years based on the average price of one year to the average price of the next year. And in three of those years, prices were recovering from the industry's financial crisis of 1974.

A number of alternatives to higher electric rates to solve the industry's lack of sufficient financial integrity have been proposed, but I believe that the traditional electric utility model will prevail.

Of these alternatives, Government can be of the greatest help by making the FERC a model of equitable regulation. Government can also help by reducing dividend taxation and inflation. Acceleration of nuclear licensing and implementation of a solution for nuclear waste disposal would also help.

Next in line among these alternatives is diversification, and least likely, in my judgment, is the deregulation of generation.

More likely than these structural change options or alternatives is the continuation of the traditional model. The traditional model, nonetheless, will require four items:

First, adequate recognition by regulation of the true cost of capital and an ability for the companies to earn their cost of capital.

Second, increased aggressiveness by management in obtaining a fair price for the service it provides.

Third, more effective customer communication by management which explains to ratepayers why electric costs are rising and what management is doing to keep these costs as low as possible.

Fourth, some help from a stabilization or reduction in the inflation rate and reductions in planned construction expenditures where justified for some companies.

Thank you.

Mr. Fuqua. Thank you very much.

[The prepared statement of Mr. Benore follows.]

TESTIMONY TO THE COMMITTEE ON SCIENCE AND TECHNOLOGY

U. S. HOUSE OF REPRESENTATIVES

by

CHARLES A. BENORE
First Vice President

PAINE WEBBER MITCHELL HUTCHINS

June 23, 1981

Electric utility common stocks are trading at about one-half of their 1965 value, and in 1965 dollars of constant purchasing power about one-fifth. Clearly the electric power industry has been a bitter disappointment to investors.

One does not have to look far to find the problem. Profitability and its quality in electric utilities has been well below that of most companies. As shown on page 1 of the exhibits, the return on equity for the 1970-1980 period has remained at about 11% while profitability of industrial companies as measured by the Standard & Poor's 400 Industrials rose from about 10% in 1970 to over 16% in 1979 and fell to 15% in the recession year of 1980.

The quality of the return on investment also varies. Electric power companies with long investment lead times and capital intensive projects accrue substantial amounts of allowance for funds during construction credits. AFUDC, in fact, accounted for 55% of 1980 earnings per share. Investors are averse to AFUDC earnings because cash in hand is more valuable than the promise of cash or an I owe you, over the next 30 to 40 years. From a quality perspective, investors recognize that cash earnings to pay cash dividends are earnings per share less AFUDC per share. This is so because depreciation is a return of, not on, capital, and because deferred taxes are ultimately paid on the property they stem from. Unfortunately, electric power companies are in the unsound position of paying out more in dividends than cash earnings, as is shown on page 2 of the exhibit.

Electric utilities have performed poorly because of adverse changes in the arithmetic of the electric business including:

1. The cost of generating plant per kilowatt has substantially increased;

2. Larger investments of a non-revenue producing nature to meet regulatory and environmental requirements to construct and operate an electric power system are now present;

3. Inflation has greatly increased, which has caused costs, including capital costs, to rise at a rapid rate;

4. Sales and revenue growth has dramatically slowed while cost growth has accelerated; and

5. Companies have not been able to sufficiently reduce costs or increase revenues in response to these changes and attain a satisfactory level of financial integrity and to make their securities relatively attractive to investors.

One might blame management of utility companies for the problems, but poor management is unlikely to be so widespread. Moreover, numerous management audits have been made of utility management, and the conclusions have been favorable by a wide margin. The principal problem, in my judgment, is the lack of adequate rate relief to cover the costs of providing electric power service including capital costs. For example, as inflation has steadily increased over the last two decades, so has the cost of capital. This is evident from the chart of the costs of senior capital shown on page 3 of the exhibit. In 1970, the cost of lowest-risk, long-term capital, or U. S. Government bonds rose from 6% to 7% to over 12% currently while the return on equity of electric companies remained at about 11%. The book return of 11% is currently less than the maturity return on lowest-risk, long-term capital, or U. S. Government bonds. This is an untenable position for the electric power industry, and one which clearly threatens its survival and ability to continue to supply reliable electric power service.

Moreover, electric companies do not earn the capital returns allowed and considered fair by regulation. Typically, as shown on page 4 of the exhibits, the gap between allowed and earned returns on common stock equity is 2 to 4 percentage points. Returns of less than what regulation considers fair are by definition unfair returns. It is unreasonable to expect investors to accept unfair returns, and it is disturbing to investors that regulation does not correct this inequity. Too, investors are disturbed when they are told that regulators are doing all they can do in consideration of consumer pressures. This means to investors that they are expected to subsidize the cost of utility services. Investors want and deserve a fair return for the use of their capital, and they cannot be forced to make unfair investments.

The financial condition of the electric power industry unfortunately has deteriorated so much that confiscation of per-share capital investment and return regularly occurs. As shown on page 5 of the exhibit, when new common stock is sold at less than book value, or less than the original investment per share, the investment per share falls from $10.00 to $8.57 when selling $200 of new common stock at 0.5 times book value, and the per-share earnings fall from $1.10 to $0.94. This is an absurd prospect for investors.

It is not surprising in view of these adverse conditions, that electric power companies are having trouble in raising capital. About one-half of bond financing by electric power companies over the last 12 months had a term of ten years or less because investors are less willing to buy 30-year bonds in this high inflation environment, and also in part because a typical bond financing reduces fixed charge coverages by 30 to 50 basis points. Such pressure on interest coverages increases the likelihood of further bond rating reductions of electric utility bonds.

The industry is also having trouble in finding buyers for its common stock. In December, 1980, for example, electric companies planned to raise about $600 million of common equity capital, but could sell only $353 million. In fact, there were three months in 1980 when electric utility companies sold less than three-quarters of the common stock desired. These capital attraction problems are unmistakable signals that the lack of financial integrity is threatening the ability of electric companies to attract capital.

The basic problem boils down to an inability to make money in electric utility common stocks. Such stocks, as measured by the Standard & Poor's 22 Electrics, as you can see on page 6 of the exhibit, have steadily declined in price since 1965, and the average price from one year to the next has risen in only four of the last fifteen years.

Despite capital attraction problems, there is not the immediate prospect of a shortage of electric power in most parts of the country. Capacity reserve margins average about 30% compared to 20% considered necessary to maintain reliable service. There is reason to be concerned, nonetheless, about America's dependence on foreign oil and the continuity of adequate electrical service in the 1990s. While 1990 appears to be a long way off, it takes almost ten years to build a power plant, and as a result, decisions about future power supply must be made now. Also of immediate concern is the ability to attract the necessary capital to convert substantial amounts of oil capacity to coal or renewable energy sources to reduce the dependence on foreign oil, and in some cases, to reduce the cost of electric power as well. Moreover, electric power companies may make a critical contribution to reducing our dependence on foreign oil through the electric car.

It is unfortunate, therefore, that some managements of the electric power industry which are confronted with the persistent inability to recover the costs of providing electric service are forced to defer and cancel capacity. In some instances the capacity is necessary to displace oil and to provide for future energy needs as existing plants need to be replaced and as energy use continues to increase even after conservation efforts. The stage is set, as I see it, for consumer concern and anger about rising energy prices to turn to anger and outrage if electric power shortages are allowed to develop in the 1990s.

A number of alternatives to higher customer rates have been proposed, but I believe the traditional electric utility model will prevail. Of these alternatives, renewables have higher costs to customers than coal, although there are advantages to utilities because of their shorter lead times and the associated ability to recoup costs faster than with conventional sources.

Generation deregulation is not a reasonable solution for the industry's problems because: (1) the electric power industry needs help now and not a decade from now, and (2) a reasonable businessman is unlikely to commit capital to a multibillion-dollar project with no payback for a decade or a decade and a half, other than tax deferment of profits from other businesses; incur regulation or lack of control involved in siting, construction, environmental, safety, and other requirements; experience a cost probably higher than the utility because of the lack of experience and organizational infrastructure; and add capacity to an industry already with overcapacity and with uncertain load growth Not many, if any, are likely to rush to such an investment proposal.

If for no other reason than the uncertainty of the future inflation rate, cost plus contracts would likely be required by such investors, and capital costs would be built into the contract with a cost above that which regulators allow and on the basis that the returns can be earned. There would also be questions about the reliability of service, coordination of transmission systems and transfer of economy power, and the impact on electric power companies which may incur problems in recovering costs of existing plants as the transition to a competitive generation system occurs. I agree with Matthew Holden FERC Commissioner, who recently said that "I would regret to see deregulation of generating capacity become a diversionary intellectual fad, while time is wasted in not dealing with the practical money problems we already know."

Federal Government involvement, as another option, can influence state regulatory practices, taxes paid by corporations, and taxes paid by investors on investment returns.

Many recommendations have been made to resolve the electric power industry's financial problems, including those of an informal task force headed by Gordon Corey (Retired Vice Chairman of Commonwealth Edison) to the Energy Transition Team of the Reagan Administration which are noted below.

Summary List of Recommendations

"1. The Federal Energy Regulatory Commission (FERC) should initiate a rulemaking to establish new generic standards for utility ratemaking at the Federal level in order to alleviate its financial difficulties.

2. Congress should be asked to authorize FERC to prescribe voluntary guidelines to aid state utility regulation in accomplishing the foregoing purposes.

3. FERC should adopt a general rule requiring CWIP* to be included in rate base. (General adoption of this recommendation would be facilitated by tax legislation to allow depreciation of CWIP for tax purposes if included in rate base.)

4. FERC should base rates of return on wholesale electric rates on its own determinations of fairness, and not be bound by state determinations.

5. Legislation should require federally regulated wholesale electric rates to become final a year after filing, if FERC has not taken definitive action by that time. FERC's present authority to suspend filings for five months should be with discrimination, in cases where there is no prima facia showing of need. In other cases, the rates should go into effect promptly, subject to refund depending on the outcome of the proceeding.

6. Tax legislation is needed to stimulate savings and investment. Proposals to accomplish this include treatment of reinvested dividends in the same way as stock dividends, thus minimizing individual income taxes thereon, establishment of a 50% tax ceiling on investment income, increased dividend exclusion, full or partial exemption of dividends on new-issue stock, etc.

*Construction-work-in-progress; investments therein amount to over $50 billion for the U. S. electric power industry as a whole.

7. IRS regulations should be revised to allow current tax deductions for future waste disposal and nuclear plant decommissioning costs.

8. Legislation is needed to provide federal loans or grants for conversion or replacement of oil-fired generation--the loans to be repayable out of fuel cost savings. Such action is necessary because of the time pressure for conversion from oil to coal.

9. In addition to the foregoing, legislation should be considered to accelerate the completion of new power plants in order to ensure adequate future power supplies and reduce our dependence on foreign oil.

10. Finally, the Task Force urges prompt appointment of a small Presidential work task force to review and draft legislation to free the electric power industry from unnecessary regulation, to ensure that tax incentives designed to encourage the development of productive facilities are unencombered by arbitrary restrictions which inhibit realization of the original objectives of the Congress, and to study deregulation possibilities."

Government can impact the financial integrity of electric companies through taxation. Increased depreciation allowances would help cash flow such as proposed in the Administration's tax program for companies that have sufficient taxable income. Unfortunately, the companies that need the most help are often those that do not pay current taxes.

Another way of helping utility companies to attract capital is to reduce, relative to other investment alternatives, the taxation of investment returns. Too, the Federal Government can help by accelerating the licensing of nuclear power plants and implementing solutions to nuclear waste disposal. Helping to reduce inflation, of course, would also benefit electric power companies.

Diversification, as another potential solution, can help, but like some of the other options, it is unlikely to solve the industry's financial problems. Diversification would have a small incremental impact because of the large size of most electric power companies, and its impact would be gradual and not immediate in nature. Furthermore, the economic problem of the electric power business earning less than a fair return would still prevail.

Of these options, government can be of the greatest help by making the FERC a model of regulation which is fair to both customer and investor interests, and by reducing dividend taxation and inflation. Acceleration of nuclear licensing and implementation of a soluton for nuclear waste disposal would also help. Next in line is diversification which could add a marginal benefit as could renewable energy sources providing customers were willing to pay their higher costs. Least likely is the deregulation of generation.

More likely than these structural change options, is a continuation of the traditional model. The traditional model, nonetheless, will require (1) adequate recognition by regulation of the true cost of capital, and that capital returns must be earned over a period of time; (2) increased aggressiveness by management in obtaining a fair price for the service provided, which includes "earning" a fair return on capital; (3) more effective customer communication by management which explains to ratepayers why electric costs are rising and what management is doing to keep cost increases as low as possible; and (4) some help from a stabilization or reduction in the inflation rate and reductions in planned construction expenditures where justified for some companies.

Exhibit Page 1

A Comparison of Certain Financial Ratios For Standard & Poor's 400 Industrials and Electric Power Companies, 1970-1980

	Price-to-Book Value (1)		Cash Flow to Construction (2)		Pretax Interest Coverage (3)		Effective Tax Rate (4)		Common Equity Ratio (5)		Return on Average Common Equity (6)	
	Standard & Poor's 400	Electric Power Industry	Standard & Poor's 400	Electric Power Industry	Standard & Poor's 400	Electric Power Industry	Standard & Poor's 400	Electric Power Industry	Standard & Poor's 400	Electric Power Industry	Standard & Poor's 400	Electric Power Industry
1980	N.A.	0.7X	N.A.	32%	N.A.	2.5X	N.A.	29%	N.A.	38%	15.0%	11.2%
1979	1.2X	0.7	98%	35	7.8X	2.7	46%	31	71%	37	16.7	11.1
1978	1.2	0.8	98	39	7.7	2.9	48	34	71	37	14.8	11.3
1977	1.3	0.9	97	43	8.1	2.9	48	34	71	37	14.2	11.4
1976	1.4	0.8	104	46	8.1	2.8	48	32	71	36	14.0	11.5
1975	1.3	0.7	92	42	7.1	2.7	51	30	70	35	12.4	11.1
1974	1.3	0.7	90	30	8.2	2.5	50	25	71	34	14.6	10.6
1973	1.9	1.0	104	30	8.6	2.8	45	26	71	35	14.3	11.5
1972	2.1	1.1	98	30	8.1	3.0	46	27	70	35	11.8	11.7
1971	1.9	1.3	90	29	7.5	2.9	44	28	71	35	11.0	11.6
1970	1.7	1.2	75	30	7.1	3.1	43	31	71	35	10.4	11.8

(1) Average of High and Low Market/Year End Book Value Per Share
(2) Deferred Taxes, Depreciation Expense, and Additions to Retained Earnings (Less AFUDC)/ Construction Expenditures (Less AFUDC).
(3) Gross Income Plus Federal and State Income Taxes/Total Interest Expense.
(4) Federal and State Income Taxes/Net Income Plus Federal and State Income Taxes.
(5) Total Common Shareholders Equity/Total Capitalization.
(6) Earnings for Common Stock/Average of Beginning and Year End Common Equity.

Source: Moody's, Standard & Poor's, and Edison Electric Institute

Exhibit page 2

Dividend Safety Indicators

	Cash Flow Dividend Coverage (1)	Cash Earning Dividend Coverage (1)	Payout Ratio (1)	Incidence of 90-100% and Over 100% Payout Ratio (2)	
				90-100%	Over 100%
1981E	2.1X	66%	75%	3	0
1980	2.0	56	76	8	2
1979	2.3	68	74	5	5
1978	2.5	82	72	6	3
1977	2.7	92	68	3	0
1976	2.8	99	67	1	0
1975	2.7	97	67	2	0
1974	2.5	91	68	6	1
1973	2.5	105	65	0	0
1972	2.5	109	65	2	0
1971	2.5	112	67	0	0
1970	2.4	118	68	1	0

(1) Electric Power Industry
(2) PWMH 45 Company Group. In 1980 DQU and LOU were were replaced by AZP and HE.

Exhibit page 3

I CYCLICAL INDICATORS

B CYCLICAL INDICATORS BY ECONOMIC PROCESS—Continued

Chart B7. Money and Credit—Continued

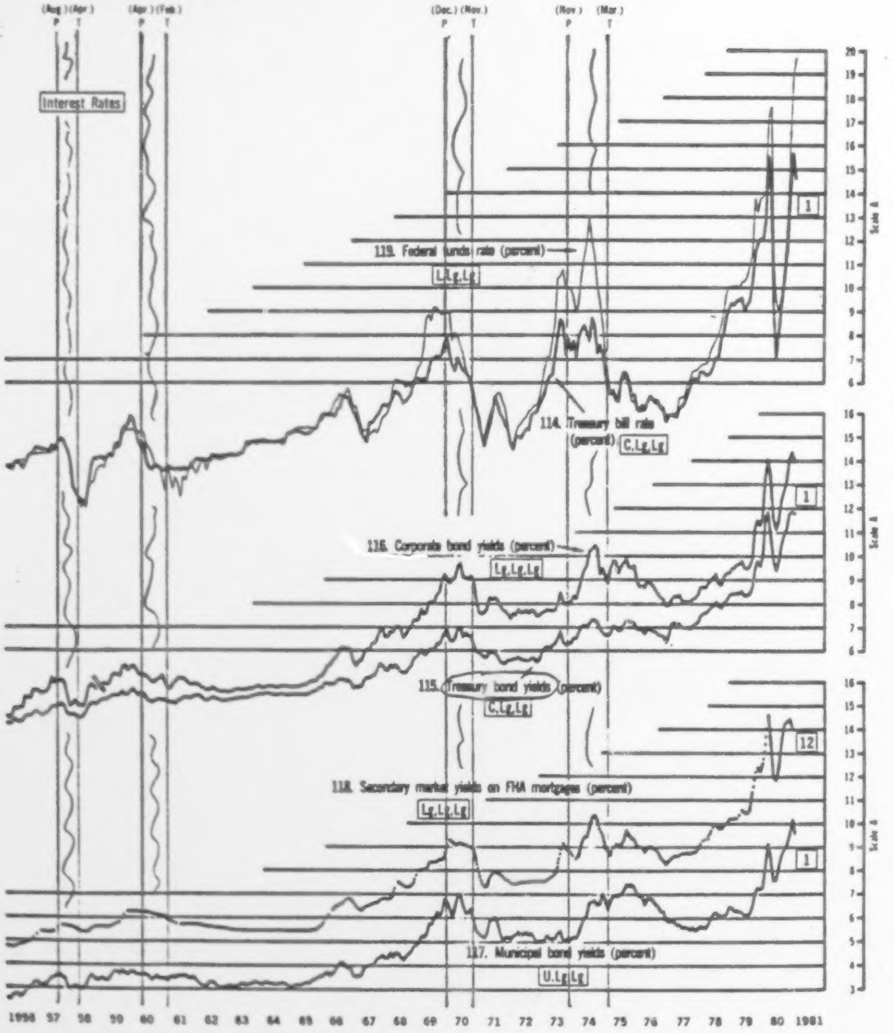

Exhibit page 4

Allowed and Earned Returns
on Year-End Common Stock Equity
For Investor-Owned Electric Utilities and Processing Time

	Allowed (1)	GNP Deflator	Real Return	Earned	Allowed Earned Difference	State Commissions Processing Time in Months
1981E	14.8%	10.4%	4.4%	11.4%	-3.4%	N.A.
1980E	14.3	9.0	5.3	10.7	-3.6	8.8
1979	13.2	8.5	4.7	10.6	-2.6	11.5
1978	13.2	7.3	5.9	10.8	-2.4	10.8
1977	13.1	6.0	7.1	10.8	-2.3	9.7
1976	12.8	5.2	7.6	10.8	-2.0	12.1
1975	12.9	9.6	3.3	10.5	-2.4	9.7
1974	12.5	9.7	2.8	10.2	-2.3	10.5

(1) States are generally on year-end

Source: Edison Electric Institute, PWMH, DRI

Exhibit page 5

Effect of a Declining Price-to-Common Equity Book Value Per Share on Earnings Per Share, Assuming Sale of New Common Stock of $200

	Base Period Data	Book Value Level		
		2.0X	1.0X	0.5X
Common Shares Outstanding	100	110	120	140
Common Stockholder's Equity	$1,000.00	$1,200.00	$1,200.00	$1,200.00
Return on Common Equity	11%	11%	11%	11%
Net Income Available to Common Shareholders	$110.00	$132.00	$132.00	$132.00
Book Value	$10.00	$10.91	$10.00	$8.57
Common Stock Sale Price		$20.00	$10.00	$5.00
Earnings Per Share	$1.10	$1.20	$1.10	$0.94

AVERAGE PRICE OF STANDARDS & POOR'S ELECTRICS,
AND AVERAGE PRICE IN 1965 CONSTANT PURCHASING POWER DOLLARS
1965 - 1980 AND 3/11/81

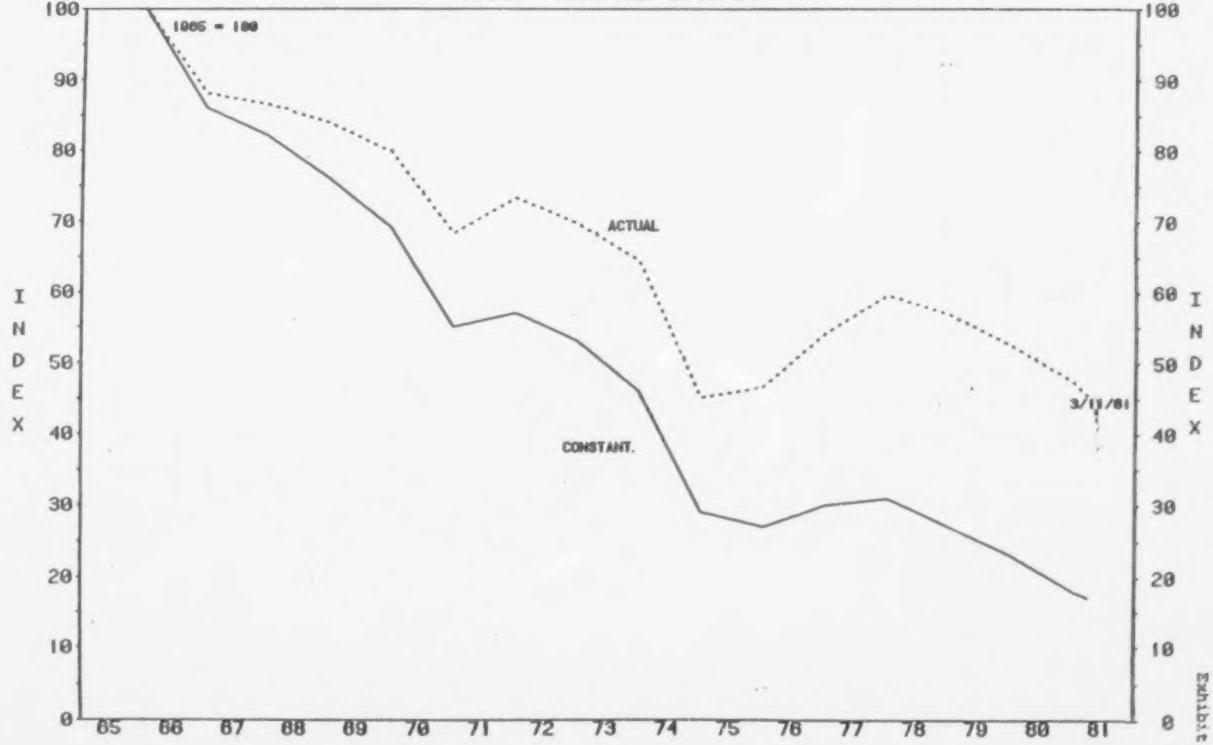

Exhibit Page 6

Mr. Ferrar.

Mr. **Ferrar**. Today I want to break my remarks into three somewhat separable sections. The first is to discuss some of the parameters Mr. Benore has covered. Therefore, I will not go through them. I am in agreement with the data given by Mr. Benore.

Mr. **Fuqua**. Let me say that without objection your statement in its entirety will be made part of the record if you want to summarize.

Mr. **Ferrar**. I will summarize.

Mr. **Fuqua**. And it will be greatly appreciated.

Mr. **Ferrar**. The second section of my statement which is submitted for the formal record I will go through more slowly, and that is try to infer from the financial condition and the regulatory posture what are the technology choice motivations that this industry might be operating within, which I believe is the most pertinent consideration of this committee.

And the third thing I will do in a very brief manner is to touch upon the subject of diversification and deregulation, but I will not go through the complete text of my remarks on that section. It would be too lengthy at this time.

In addition to endorsing Mr. Benore's remarks, I feel there is one other dimension of the regulatory process that has to be brought into focus if we are to look upon marketplace acceptance by this industry of various technologies.

This feature deals with the fact that management and industries have to make decisions in the long run based on expected risk and rewards of the decisions they make. In times of rapid inflation and changing regulatory practices, capital-intensive, long-lead-time problems create a risk exposure that has to be considered in decisionmaking on technology.

Moreover, as the TMI experience has shown, there is a tendency for regulatory authorities to disproportionately burden stockholders with risk while rewarding ratepayers with the efficient gains associated with successful projects.

As exhibit 1 to my testimony, I provide an article I authored in the summer of 1979 dealing with the TMI accident, which demonstrates what I would like to refer to as an asymmetric risk-reward performance by utility commissions. The rewards in effect go to ratepayers in large measure and the risks go to stockholders in large measure.

For example, in this article I identify that when all generation costs are considered, TMI-2 would yield a 25-percent savings per megawatt hour when compared to a coal-fired plant, which at the time I did that analysis was the closest economical alternative. However, the rate regulatory process rewarded GPU investors with really no higher rate of return on this facility than the rates that were set for other facilities owned by GPU—for example, utility poles and buildings.

Thus, the rewards of economic efficiency of this technology were intended to accrue to customers in the form of lower rates, but as we see now, with the advantage of 20-20 hindsight, the technology risks were indeed larger for this project and resided primarily with the investors—at least to the extent feasible just short of bankruptcy.

Given this expected risk and reward assessment by investors, and the risk-reward asymmetry of the regulatory process, it is possible to identify what I would suggest to you as technology-choice principles. In no way are these exhaustive, and in no way have these withstood the test of peer group review in the literature, but I believe they are rather straightforward.

Perceived investor risk is increased by: project capital intensiveness; absolute project size; the project size relative to the sponsoring organization; and the length of the construction period.

I believe these are some parameters you might keep in mind as you think about market acceptability of various technologies.

Again, perceived investor risk is decreased by: the industry experience with the technology; and a positive social assessment of the technology.

Similarly, the expected rewards of life-cycle economic efficiency offered by the technology, which in principle should balance the additional investor risk, are largely denied to the investor by the asymmetric risk-reward performance of rate regulation I outlined above.

This was demonstrated by my earlier TMI example, but let me give you another brief example to show this is not uniquely a TMI factor.

Northeast Utilities, a Connecticut utility, has clearly shown that the life-cycle savings which would result from the construction of an additional unit at the Millstone 3 nuclear facility would yield life-cycle savings to the customers. However, this project has been repeatedly delayed primarily because of the failure of the Connecticut Department of Public Utility Control to grant adequate rate relief to Northeast Utilities.

These factors, therefore, have an impact upon technology choice by affecting investor risk-reward expectations in the technology decisionmaking process.

The above discussion shows, therefore, coupled with Charlie Benore's discussion, that the electric power industry is in a condition of financial weakness, and it is operating in an asymmetric risk-reward investment environment. Both of these factors, I feel, are fundamental to the considerations of this committee regarding the market acceptability of technology in the future.

EEI and the industry are working aggressively, as I covered elsewhere in my remarks and thus will not cover in the oral testimony, to improve the environment, but the results of this condition are several-fold.

First of all, it results in plant deferrals and cancellations. For example, from 1974 through January 1, 1981, there have been 90 plant cancellations and probably over 200 deferrals. While some of these plant deferrals and cancellations can be attributed to lower-than-expected growth rates in requirements for electric power, the investment factors I have outlined above are playing significantly upon decisionmaking in this industry.

In addition to the cancellation and deferral option, the technology-choice principles I have outlined can also be applied to technologies of particular interest to this subcommittee.

For example, nuclear. As pointed out in the Northeast Utilities and GPU experiences cited above, considerable economic savings can result from this technology, and in many jurisdictions the possibility to displace imported oil is quite significant. However, nuclear is a highly capital-intensive technology, its absolute size is large relative to typical sponsoring organizations, and its construction period is extended.

Similarly, while the industry's experience with this technology is quite significant—it does not benefit from a positive social assessment.

For these reasons, the nuclear technology option, while often cost effective and consistent with the national energy policy, is not prone to be considered as a highly likely technology under today's regulatory environment and today's financial condition.

Coal seems to be a safe choice for the industry in today's regulatory economic climate. It has received a measure of social acceptability, there is considerable industry familiarity with the technology, and it offers more flexibility in terms of facility size.

Cogeneration offers the advantage of possible capital-cost sharing with other industries. The absolute size of the project can be tailored to load requirements. It has a positive social assessment, and there is considerable industry experience in this technology.

I will comment more on cogeneration when I get to the subject of diversification and leave most of the comments on that subject to Mr. Mitchell who will be appearing before you tomorrow.

New technologies such as solar, wind, et cetera, I'd like to discuss briefly.

Applying my suggested technology-choice principles to these technologies, we note the following:

In most cases they are capital-intensive, there is a limited industry experience with them, and social acceptability of these technologies, while on the surface looks very positive, is really yet to be fully established in the marketplace.

As a result, my preliminary review would indicate that they are not likely to be a primary choice by the utility industry under the current regulatory economic environment and the current state of knowledge of these technologies.

Conservation. Everyone agrees that conservation is desirable, yet the industry's financial weakness, Mr. Benore has indicated, prevents it from aggressively pursuing these technologies. Many conservation alternatives are capital-intensive, and indeed many oil- and gas-conserving technologies require the use of additional electric power to displace these fuels.

While this industry is in an excellent position to assist in improving the energy efficiency of this economy, its unwillingness to reach to external sources of capital due to its weak financial posture makes it rather slow in moving on these conservation options as compared to what it would be if we had a more financially healthy industry.

As a summarizing statement to my remarks on this, I note that the industry's weak financial health tends to retard aggressive pursuit of any technology options that require external sources of capital. That is the bottom line to these remarks. Given the asymmetric risk-reward performance of utility commissions, there is also a tendency to reach to relatively riskless technologies. Many of the technologies that are endorsed by this administration will suffer in the marketplace unless the overall regulatory-economic environment is improved, and emphasis on life-cycle economic efficiency reestablished.

Further, if the financial health of this industry were to be reestablished and the regulatory-economic environment neutralized regarding technology choice, the drive for economic efficiency would, in my opinion, be adequate to guide and finance required technology research and development efforts through the private sector. Under such conditions, perhaps the DOE R. & D. work could be reduced or retargeted toward more basic research considerations.

The utility industry, as I outlined in my written remarks, is working diligently toward improving the rate-regulatory process in a manner that can accommodate an inflationary economy while creating a risk-reward decision environment that better rewards economic efficiency in technology choice.

I will note that diversification is not intended to be a panacea to the industry's problem. At EEI we are reviewing the significance of this trend and have recently completed a survey that provides some insight in this regard. Of the 125 companies responding to the EEI survey, 79 companies—63 percent of the respondents—had at least one business venture outside the traditional generation, transmission and distribution function. There were 247 ventures defined in the survey, and of this 77 were unregulated subsidiaries of the parent utility company.

I enclose the data detailing this in my written remarks for your review.

One particular diversification option that deserves attention here is cogeneration and small power production, and we have testified before Congress on several occasions regarding modifications in PURPA and the Energy Tax Act of 1978. As I know this will be covered in great detail by Mr. Mitchell tomorrow, I will not go into that at this time.

My last comment regards the subject of deregulation which was requested in the letter of invitation.

Deregulation logically should be considered in a changing technological and economic environment. Such changes potentially may render the fundamental call for regulation unnecessary as latent competition may become available in specific submarkets.

EEI is examining the practical consequences of deregulation and further information will be forthcoming. But at this time I would like to caution that one must not assume as immediately relevant the deregulation experience in other industries. The transfer of those experiences without careful tailoring to the characteristics of the electric power industry should be guarded against.

This industry is the most capital intensive—long leadtime, geographically fixed, and highly integrated industry in this economy, and these circumstances must be understood in any practical consideration of deregulation. It is difficult to conceive of planning on a 30-year horizon for an integrated system to supply cost-effective and reliable service without some of the stabilizing benefits available in the current regulated environment.

Capital requirements for central-station power facilities are so significant that there is not a readily available private sector, financial market model to analyze the impact of deregulation on technology choice. If regulation of generation is simply replaced by regulation of construction contracts and procurement practices, what is the social gain?

These are the issues we are attempting to put some meat on in our investigations at the institute.

In summary, we are in a time of significant institutional reconsideration concerning rate regulation of the electric power industry. Unquestionably these institutional changes will have an effect on technology choice, and the overall profitability and reliability of supply of electric power. The industry is actively working to provide solid, factual information as a cornerstone to the assessment of alternative institutional configurations. We will keep this subcommittee informed as to our results.

Thank you for the opportunity to appear.

[The prepared statement of Mr. Ferrar follows:]

Statement By the Edison Electric Institute

Presented By

Terry A. Ferrar
Vice President, Economics
Edison Electric Institute

Before the House Subcommittee
on
Energy Development and Applications

"The Future of the Nation's Energy Utilities"

June 23, 1981

It is a pleasure to appear before this subcommittee and to discuss some issues of pertinence to the "future of the nation's electric utilities." The letter requesting my presence indicated the subcommittee's interest in "institutional issues" that might have an impact on the trajectory of this industry and its selection of technology options. I have organized my remarks into three sections: First, I will review some data which demonstrate the current financial difficulties of the investor-owned utility industry; second, I will suggest the implications of this financial condition for technology choice; third, I will touch upon the institutional topics of diversification and deregulation.

The deteriorated state of this industry's financial position is evidenced by many familiar indicators. In 1980 the earned return on common equity was only 11%, while new rate increase applications were seeking returns from 16-18% to reflect current utility costs of capital. Utility stock is selling at approximately 70% of book value, and new long-term debt instruments are being issued with interest rates of 16%. In effect, investors in electric utility common stock are being rewarded with a minus 5% risk premium, and an earned rate of return which is less than that earned on U.S. Treasury notes (six-month Treasury notes are earning approximately 14% currently.) The absence of a risk premium is at the heart of this industry's finanical problems, and it is determinative regarding technology choice.

The industry's financial trouble is also evidenced by the portion of net income accounted for by the Allowance For Funds Used During Construction (AFUDC). AFUDC is a non-cash earnings account which shows up in a utility balance sheet but not in its cash flow. In 1980 the AFUDC's share of income climbed to 46%, while only three years earlier it was 30%. This erosion of the cash component of income also reduces the ratio of internally generated funds to construction expenditures--in 1980 this ratio dropped to 28%. As recently as 1976 it had been 40% (most financial analysts claim it should never drop below 50%). It is simply naive to assume that investors will be willing to accept promises of future payment, in the form of AFUDC entries on finanical statements, in these times of rapid economic change.

This financial deterioration is not a recent or transient phenomenon. It did not begin in 1979 or 1980--or even in 1974. Since the early 1970s every major finanical indicator--market-to-book ratio, debt cost, bond ratings, interest coverage ratio, return on equity and quality of earnings--has shown a consistent decline. Even if you statistically remove the perturbation surrounding the crisis and recovery in 1974, in real terms at the end of the 1970s most indicators were worse than pre-1973 levels. The financial difficulties of this industry are chronic.

Moreover, these financial problems are in general more severe than the financial difficulties facing other industries. For example, the average market-to-book ratio for all industrials in 1980 was 143%, whereas this ratio for the investor-owned utility industry was (as indicated above) approximately 70%. Other similar indicators suggested that this problem is of unique importance to this most capital-intensive, long-lead time industry.

Today's rate-regulatory structure is overstressed by inflation. For example, Savannah Electric and Power Company is heavily burdened by the unresponsiveness of the regulatory process to today's economic conditions. For a period of approximately four months of this year, this company was incurring capital costs related to its Effingham Unit, while no recovery of these costs was permitted from the customers receiving its output. The lack of these additional earnings -- attributable to regulatory lag -- resulted in severe impact on the company's balance sheet. This mismatching of inservice dates with rate-base recovery of the costs of assets is a significant burden to this industry, because inflation assures that new units account for a major portion of a company's total assets.

There are many other weaknesses of the rate-regulatory system that tend to be accentuated by inflation. One worth emphasizing is that utility rates are established as if generating plants can be replaced at the end of their service lives for the same cost for which they were originally built. Indian Point II, a Consolidated Edison Company of New York facility, cost approximately $250 million dollars to complete, yet Con Edison estimates that by the time this unit is retired it will cost in excess of $6 billion dollars to replace. Nevertheless, Con Edison has been permitted only to charge enough to recover its original cost. In essence, there is a significant real cost of service that is not being recovered by today's "cost of service" ratemaking and accounting principles.

Regulatory lag and the use of accounting principles that are backward looking assure that costs are understated and earnings overstated and overtaxed. As a result, investors' capital tends to be eroded with the result that utilities continually require massive amounts of new capital --from external sources-- merely to maintain existing capacity alone, even if we ignore additional growth-related capital requirements. If commissions do not modify their policies and practices, a "day of reckoning" will come before the end of this century that will confront regulators and the utility industry alike with a hard choice--enormous rate increases to accommodate virtually the entire cost of replacing necessary utility equipment, or a reduction in quality and reliability of service.

Before turning directly to the question of technology choice by this industry, I must briefly review with you one other feature of management within today's regulated environment. In the long run, management must make decisions based upon the expected risks and rewards of their actions. In times of rapid inflation and changing regulatory practices, capital-intensive, long-lead-time projects create a risk exposure that must be considered in technology choice. Moreover, as the TMI experience has shown, there is a tendency for regulatory authorities to disproportionately burden stockholders with risk, while rewarding ratepayers with efficiency gains associated with successful projects. As exhibit I to this testimony, I provide an article that I authored in the summer of 1979 (following the TMI accident) which demonstrates an asymmetric risk-reward performance of utility commissions--rewards go to ratepayers and risks to stockholders. For example, in this article I identify that when all generation costs are considered, TMI-2 would yield a 25% savings per megawatt hour when compared to a coal-fired plant (the closest economic alternative). However, the rate-regulatory process rewarded GPU investors with no higher rate of return on this facility when rates were set, than the rate of return these investors could expect from much less risky investments--e.g., utility poles or buildings. Thus the rewards of economic efficiency of this technology were intended to accrue to customers in the form of lower rates, but (as we now see) the technology risks continued to reside primarily with the investor--at least to the extent feasible just short of bankruptcy.

Given this expected risk and reward assessment by investors, and the risk-reward asymmetry of the regulatory process, it is possible to identify some technology-choice principles: (not intended to be exhaustive)

Perceived investor risk is increased by

- project capital intensiveness
- absolute project size
- project size relative to the sponsoring organization
- length of construction period

Perceived investor risk is decreased by

- industry experience with the technology
- positive social assessment of the technology

Similarly, the expected rewards of life-cycle economic efficiency offered by a technology (which should balance additional investor risk) are largely denied to the investor by the asymmetric risk-reward performance of rate-regulation. This was demonstrated by my earlier TMI example as well as the following Northeast Utilities experience. Northeast Utilities (in Connecticut) has clearly shown the life-cycle savings which would result from the construction of an additional unit at the Millstone nuclear facility. However, this project has been repeatedly delayed because of the failure of the Connecticut Department of Public Utility Control to grant adequate rate relief to Northeast Utilities. These factors (therefore) have an impact upon technology choice by affecting investor risk-reward expectations in technology decision making.

The above discussion shows, therefore, that the investor-owned electric power industry is in a condition of financial weakness, and it is operating in an asymmetric risk-reward investment environment--both of these factors affecting the technology choice process. The results are apparent--plant deferrals and cancellations. For example, from January 1974 to January 1981, there have been 90 plant cancellations and probably over 200 deferrals. While some of these plant deferrals and cancellations can be attributed to lower than expected growth rates in requirements for electric power, the investment factors I have outlined are playing significantly upon decision makers' appraisals of the desirability of continuing construction programs, or investing in new, riskier technologies.

In addition to the cancellation and deferral "option", the technology-choice principles I have outlined can also be applied to technologies of particular interest to this subcommittee For example:

- Nuclear--As pointed out in the Northeast Utilities and GPU experiences cited above, considerable economic savings can result from this technology, and in many jurisdictions the possibility to displace imported oil is quite significant. However, nuclear is a highly capital-intensive technology, its absolute size is large relative to typical sponsoring organizations, and its construction period is extended. Similarly, while the industry's experience with this technology is quite significant, it does not benefit from a positive social assessment. For these reasons, the nuclear technology option, while often cost-effective and in the national interest in terms of reducing imported oil, is not prone to be chosen by management.

- Coal--Coal seems to be a "safe" choice for the industry under the current regulatory-economic conditions. It has received a measure of social acceptability, there is considerable industry familiarity with the technology, and it offers more flexibility in terms of facility size. Therefore, my suggested technology-choice principles view coal as a favorable technology option, although uncertainty about regulatory requirements is beginning to have an adverse impact on this technology.
- Cogeneration--Cogeneration offers the advantage of possible capital-cost sharing with other industries, the absolute size of the project can be tailored to load requirements, it has a positive social assessment, and there is considerable industry experience. One complicating feature of cogeneration is the inter-industry management requirements, as well as some of the restrictions contained in existing statutes and FERC regulations. More will be said on this later, when we come to diversification issues.
- New technologies such as solar, wind, etc.

Applying my suggested technology-choice principles to these technologies reveals the following. In most cases they are capital intensive, there is a limited industry experience with them, and social acceptability of these technologies is yet to be established due to their relative newness. As a result, my preliminary review would indicate that they are not likely to be a primary choice by the utility industry under the current regulatory-economic environment.

- Conservation--Everyone agrees that conservation is desirable, yet the industry's financial weakness in most cases prevents it from aggressively pursuing these technologies. Many conservation alternatives are capital intensive, and (indeed) many oil and gas conserving technologies require the use of additional electric power to displace these fuels. While this industry is in an excellent position to assist in improving the energy efficiency of this economy, its unwillingness to reach to external sources of capital due to its weak financial posture stifles this effective pursuit. Thus while conservation is being encouraged by the electric utility industry, this encouragement is not nearly as aggressive as it would be if the financial health of the industry were restored and some of the decision-making distorting features of current regulatory practices were removed.

As a summarizing statement to the above exercise, I note that the industry's weak financial health tends to retard aggressive pursuit of any technology options that require external sources of capital. Given the asymmetric risk-reward performance of utility commissions, there is also a tendency to reach to relatively riskless technologies. Many of the technologies that are endorsed by this administration will suffer in the marketplace unless the overall regulatory-economic environment is improved, and emphasis on life-cycle economic efficiency reestablished. Further, if the financial health of this industry was reestablished and the regulatory-economic environment neutralized regarding technology choice, the drive for economic efficiency would (in my opinion) be adequate to guide and finance required technology research and development efforts through the private sector. Under such conditions, perhaps the DOE R&D work could be reduced or retargeted toward more basic research considerations.

This industry is working diligently towards improving the rate-regulatory process in a manner that can accommodate an inflationary economy while creating a risk-reward decision environment that better rewards economic efficiency in technology choice. As exhibit II accompanying this testimony, I am enclosing testimony presented by H.L. Culbreath, President, Tampa Electric Company on behalf of the Edison Electric Institute before the House Subcommittee on Energy Conservation and Power. This testimony offered a number of recommendations which would improve the regulatory environment. For example, it is suggested that the Federal Energy Regulatory Commission set an example for and encourage state regulatory bodies to consider, in generic hearings, adoption of the following measures:

- using forward test periods to determine rate base and expenses for ratemaking,
- authorizing rates of return on equity which reflect the total risk (financial and regulatory) that the stockholder is being asked to shoulder,
- including construction-work-in progress in the rate base, and reflecting in the approved rates the full carrying charges on the capital invested in construction

projects,

- allowing depreciation rates which reflect the need to recover capital more rapidly in the present inflationary environment,
- permitting normalization of the benefits of accelerated depreciation and investment tax credits, and
- permitting the use of fuel adjustment clauses which enable utilities to recover fully the cost of all fuel used for power production under both normal and emergency conditions.

In addition to regulatory reform, the industry is examining what opportunities exist to continue to serve its customers while earning a reasonable return on equity by way of unregulated diversified activities. This includes the concept of "energy services companies" as well as more traditional concepts of fuel subsidiaries and other business pursuits in service to American customers. At EEI we are reviewing the significance of this trend, and have recently completed a survey that provides some insight in this regard. Of 125 companies responding to the EEI survey, 79 companies (63 percent) had at least one business venture outside the traditional generation, transmission and distribution function. There were 247 ventures defined in the survey, of which 77 were unregulated subsidiaries of the parent utility company. Table I (which follows) summarizes the results of the survey in terms of types of ventures in which utilities are currently involved.

One particular diversification pursuit that deserves attention here is cogeneration and small power production. The provisions of Section 201 and 210 of PURPA permit the operation of such facilities in an unregulated environment provided the facility is less than 50% owned by an electric utility. We believe that cogeneration and small power production hold great promise, when integrated prudently with the utility network, to improve the efficiency of energy use and reduce future construction needs. However, the current PURPA limitations on PURPA-derived benefits for utility-owned facilities will certainly affect the viability of this technology as a choice for electric utilities. By way of Exhibit III, I am enclosing testimony presented by Ralph Mitchell, Vice President of Arkansas Power and Light on behalf of EEI before the House Subcommittee on Energy Conservation and Power. As this testimony indicates, the industry is advocating modification of various statutes, and of rulemakings issued pursuant to Sections 201 and 210 of PURPA to permit the utility industry pursue these technologies more aggressively. Briefly EEI recommends the following legislative and regulatory changes to promote cogeneration development:

- Amending Section 201 of PURPA (P.L. 95-617) to allow utilities to own more than 50 percent of a cogeneration facility and be eligible for the rate and exemption privileges of a qualifying facility.
- Providing equal treatment to electric utilities with respect to cogeneration tax incentives under the Energy Tax Act of 1978 (P.L. 95-618) and Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223).
- Amending FERC regulations to implement PURPA in a manner which recognizes the full range

of purchase rates permissible under Section 210 of PURPA--not pegged at full avoided cost.

- Granting exemptions from the Fuel Use Act for new cogeneration facilities only where there is a showing of net oil/gas savings.

I should also note that the industry is actively supporting Congressman Alexander's bills H.R. 2876, which would amend the Public Utility Regulatory Policies Act to place electric utilities on the same basis as non-utilities with regard to investment in cogeneration and small power production, and H.R. 2946 which would amend the Internal Revenue Code to achieve the same end.

The subject of deregulation of the electric power industry, has become a popular topic (particularly) in recent months. Deregulation logically should be considered in a changing technological and economic environment. Such changes potentially may render the fundamental call for regulation unnecessary as latent competition may become available in specific sub-markets. EEI is examining the practical consequences of deregulation and further information will be forthcoming in the near future.

At this time, I would caution that one must not assume as "immediately relevant" the deregulation experience in other industries; and transfer those experiences without careful tailoring to the electric power industry. This industry is the most capital intensive, long lead time, geographically fixed, and highly integrated industry in this economy; and these circumstances must be understood in any practical consideration of deregulation. It is difficult to conceive of planning on a 30- year horizion for an integrated system to supply cost-effective and reliable service without some of the stabilizing benefits of the current planning environment--limited market uncertainty, centralized technology choice, land condemnation authority, coordinated planning of transmission systems with generation, etc. Moreover, the capital requirements for central-station power facilities are so significant, that there is not a readily available private-sector financial-market model to analyze the impact of deregulation on technology choice. If regulation of generation is simply replaced by regulation of construction contracts and procurement practices, what is the social gain?

As a final observation on deregulation, the existence of tax and capital-raising subsidies by publicly-owned utilities and rural cooperative utilities places them in a favorable competitive position which is incompatible with deregulation. Competition between subsidized and nonsubsidized segments of this industry will not produce economically efficient results. It must be anticipated that deregulation without reducing subsidies to public systems will result in expansion of public power supply, artifically low prices and inadequate end-use conservation.

In summary, we are in a time of significant institutional reconsideration concerning rate regulation of the electric power industry. Unquestionably these institutional changes will have an effect on technology choice, and the overall profitability and reliability of supply of electric power. The industry is actively working to provide solid, fact-based information as a cornerstone to the assessment of alternative institutional configurations. We will keep this subcommittee informed as our results are forthcoming, and we look forward to cooperating as we all pursue the common purpose of a reliable, stable, low-cost electric power supply for this nation.

Exhibit One

Public Utilities
FORTNIGHTLY

Three Mile Island — The Regulatory Challenge of 1979

By TERRY A. FERRAR

RATE case orders frequently demonstrate the regulator's concern for assuring the presence of correct incentives for management efficiency. This is normally expressed as a decision to disallow some investment-related cost from consideration in a rate case filing. The regulatory order will read, "If such costs were to be passed to the customer, proper management incentives would be distorted, therefore these costs are rightfully borne by the equity holders to which management is directly responsible."

Management is responsible to the equity holders, and irresponsible investment decisions must be shouldered by owners to assure proper management discipline. This is a principle of effective investment management, not only in regulated industries but in all investor-owned enterprises. This article will not quarrel with this concept, but rather examine its application as accented by the events' at the General Public Utilities Corporation's Three Mile Island (TMI) nuclear generating station.

Terry A. Ferrar is director of system planning for the General Public Utilities Corporation. His office is responsible for the corporations' energy and load forecast, load management and load research program, and generation capacity expansion plan. Before joining GPU he was director of the Center for the Study of Environmental Policy at Pennsylvania State University. Dr. Ferrar was graduated from Pennsylvania State University with a BS degree in engineering and received his PhD degree from Purdue University.

This article points out that the "Three Mile Island" nuclear accident has posed a regulatory challenge transcending the immediate plight of the electric utility companies directly concerned. Specifically, will the residual costs of an accident of catastrophic proportions be distributed in a way that is conducive to continued prudent but innovative investment decisions on the part of electric utility managements? The regulatory decisions distributing these costs will signal to investors that historical expectations as to the security of utility investments are warranted or unwarranted. To the extent that they are perceived to be unwarranted the costs of capital needed to develop effective new energy technologies will rise, perhaps prohibitively. It is the author's conclusion that, to assure efficient investment decision making, potential beneficiaries of any large project must assume its risks. If the group of expected beneficiaries and the group which is burdened with the attendant financial risks are not the same, the result may be an inordinate cost-of-capital impact upon the utility industry and all its future customers.

This article asserts that the TMI accident has identified a regulatory challenge that will have transcending effects upon the utility industry and the nation. (The TMI situation is the vehicle by which a generic regulatory issue is identified and studied. (The basic questions and solutions suggested in this article are not limited to the events at TMI.) Further, it suggests a risk-benefit structure to the regulatory question, and identifies the stress placed on traditional institutions by catastrophic accidents. The article concludes with a recommendation that would strengthen these institutions.

The Management Environment

The raison d'etre for regulation is to assure service of acceptable quality at minimum achievable customer cost. To satisfy this mission, the regulator monitors investment decisions to assure they are in the customer's best interest, and sets a service price which is adequate to assure the availability of sufficient financial capital for necessary maintenance and expansion of the enterprise.

Utility investors represent a specific class of preferences. They tend to be interested in secure, low-risk investment opportunities, and for this security they accept an appropriately reduced rate of return. The return is generally of a high dividend yield and low capital appreciation relative to other investment opportunities, and this type of return has appealed to retirees and others who have need for a secure current return.[1]

The role of management is to interpret creatively the preferences that it is paid to serve. Enlightened management must advocate programs and allocate the resources in its trust in a manner that will assure low-cost, reliable service, and adequate technological diversity to permit timely response to future (perhaps unanticipated) events. Management must be cognizant that actions which will sustain the satisfaction of regulator and investor preferences in the long run may not be identical with the short-term satisfaction of these same preferences. Such management can only survive in a regulatory and investor environment that is understanding and responsive.

The TMI accident has focused this issue of short- versus long-term decision making for GPU, but GPU is a microcosm of the utility industry. As with the management of most of the larger investor-owned utilities, GPU has committed significant resources to the advancement of supply options. In appreciation of the rapidly depleting domestic resource base, environmental stress amplified by conventional electric generation technologies, and national economic pressures, GPU has pursued a business path that has intentionally included technological diversity. For example, it has shared with several other utilities leadership in coal utilization, environmental control, light-water reactor development, load management, and extrahigh-voltage transmission development. This business strategy has been accomplished with the support of regulators and investors, but always at the initiative of management — as it must be.

Business Perspective on Three Mile Island Unit No. 2

GPU invested in excess of $700 million on the TMI Unit No. 2 project. The investors understood that th direct project benefits would accrue to Pennsylvania a New Jersey customers in the form of lower costs of service than for any other available alternative. Indeed, the rate-setting process has traditionally assured that the benefits of cost reductions flow to the customer, while the investor receives a reasonably secure return.

To identify and quantify the project's expected benefits, a cost comparison was conducted between TMI-2 and a coal-fired facility of similar capacity, the closest economic alternative. The result of this analysis indicates that when all generation costs are considered, TMI-2 yields a net energy cost savings of approximately $500 million (present value 1979) over the life of the facility. Alternatively, on a megawatt-hour basis the comparable coal-fired plant is 25 per cent more expensive.

To appreciate further the expected benefits of this project, studies have shown that over its four and one-half years of operation, TMI Unit No. 1 (TMI-2's sister facility) has yielded $300 million in savings compared with a comparable oil-fired unit. Th savings are currently running at the $88 million year.

GPU's capitalization is approximately $5 billion; hence, this project (TMI-2 alone) represents 14 per cent of current corporate asset value. Given the risk-averse preference of utility investors, and the realization that the project's half billion dollar benefits would accrue to the customers, on what basis was this decision rendered?

To understand the logic behind the TMI-2 investment, it is necessary to focus on the tripartite (mutually responsible) relationship among the manager, investor, and regulator. Consistent with the intent of the franchise agreement, it is understood that management has the responsibility to render decisions in a manner consistent with reliable, minimum cost service to the customers. In turn, the investor is assured that if the company satisfies this mission, then service price will be regulated consistent with the maintenance of a secure return on his equity. In essence, while in an unregulated industry investment decisions hinge on the balance of exper profit bonus versus project risk; in a regul. environment investment decisions rest on the assurance that holding customer interests foremost will ensure an adequate return on investment.

This tripartite relationship represents an institution that has served this nation well. It has provided a mechanism to permit the private sector to supply basic services under conditions of natural monopoly, while assuring the inherent economy of scale benefits accrue to the customer. Further, this regulated industry design has permitted private financial market support of the required capital investments. Notwithstanding these facts, the events at TMI present a significant challenge to this institution.

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[1] A 1978 survey indicates that GPU has an estimated 200,000 individual shareholders. The median shareholder is sixty-five years of age with a family income of $19,000. Thirty-five per cent of the shareholders have an annual income below $15,000. Seventy-eight per cent are retired, near retirement, or homemakers.

Residual Costs of the TMI-2 Accident

There are essentially two categories of residual costs associated with the TMI-2 accident. The first group of costs are attributable to the replacement power charges during the period when TMI-2 is not operating. This cost factor is accentuated by the fact that TMI-1 is being withheld from service until more normal functions can be restored to the island, and relatively minor engineering modifications are made. These replacement power costs are approximately $24 million per month during the time that both units are out of service; with the restoration of service from Unit No. 1, these costs will drop to approximately $10 million per month. To appreciate the significance of these figures, the company's average monthly revenue in 1978 was $108 million per month, and in 1979 was budgeted (before the TMI-2 accident) at $125 million per month.

The second cost category is interest on bonds, dividends on preferred stock, common stock earning requirements, depreciation, and other fixed charges associated with the TMI-2 investment. These fixed charges represent approximately $8 million per month.

The industry and the company have public liability insurance and indemnity provided by a combination of insurance policies, an assessment system for utilities owning nuclear reactors and government indemnity arrangements. Additionally, property damage insurance is provided by insurance companies. However, the above two cost categories represent financial risks for which direct insurance coverage for nuclear units is not available.

It is also relevant to observe that under normal conditions, energy clause pass throughs and allowance for funds used during construction on construction work in progress procedures provide coverage for these referenced costs in a rather routine fashion. TMI has shown that under catastrophic conditions, it is even more essential that these procedures function unless substitutes are in place; more will be said on this later.

Regulatory Scenarios

To provide definition to this regulatory challenge, two scenarios are presented. For the first case, hypothesize that it is determined the costs associated with the TMI accident are to be shouldered by the investor.

Given the characteristics of a utility investor, the investment community would respond rapidly and decisively to this information. The risk perception generated by such a decision would precipitate a rise in the cost of capital, and future customers throughout the industry would experience yet another increment in the already inflating cost of energy.

To understand better this potential financial market impact, the National Economic Research Associates was [illegible] preliminary analysis [illegible] has suggested that the investment community could be expected to respond to this new perception of risk in a way that would result in approximately a 20 per cent overall increase in the cost of capital to the utility industry. While a refinement of its work is in progress, it is notable that this increase would be registered in the market in two ways:

a) Knowledgeable investors would insist that the common equity component of the industry's capital structure be increased vis-a-vis debt and preferred stock. That is, the historical debt, preferred, and common equity proportions would be modified to favor additional emphasis on common stock. This action would directly increase the cost of capital and associated taxes.

b) The required market return on common equity would also be increased by this new perception of risk.

Both of these financial market responses would work to increase the cost of capital throughout the industry. These costs would be an immediate burden, and they would continue indefinitely until another change in the industry's risk perception occurred.

Such a regulatory action would also provide a clear signal to management. Management would observe that, while retrospective customer-economic analysis continues to support the logic of the TMI investment, the regulatory process resulted in an investor penalty. Hence, management decision making would be modified in a manner that would argue against the adoption of all but the most riskless technologies, and customer-economics would become of secondary importance. Such an amplified risk aversion would thwart the rate of technological commercialization, further stifle technological advance in this industry, and increase dependence on high-cost methods of generation.

For the second regulatory scenario, hypothesize that customer-economic justified investments are considered de facto satisfaction of management's responsibility. Hence, consistent with the tripartite agreement, the investor would be insulated from the uninsured costs of the TMI incident, and these costs would be passed to the customers. By accepting the regulatory preemption of potential project profits, the investor's normal return is now sheltered from these adverse occurrences.

The signal this would promulgate to the investment community would be that its historical expectations concerning the security of utility investments were warranted. The financial market would continue to yield relatively low-cost capital to the utility industry, and future electric customers would continue to benefit. ("Future customers" in this context is intended to suggest customers who receive electric energy from future vintage generation systems. Similarly, "current customers" implies customers receiving power from current vintage generation facilities.)

Under this scenario, the signal to management would be that society endorses prudent decisions involving innovative technologies. It would encourage decisions to commercialize evolving cost-effective technologies, and to advance the state of the art concerning the supply of electric energy.

Observation

These two scenarios provide definition to the current regulatory environment. They have shown that the regulatory question concerns the allocation of the residual costs of the accident: (a) In the first scenario, the initial burden is on GPU's investors, with financial market-driven impacts on all utility investors and all future customers; and (b) in the second scenario, current GPU customers sustain this burden.

To assure efficient investment decision making, expected project beneficiaries must assume the project's risks — the "risk-benefit principle." To the extent that those who are expected to benefit from an investment are not the same group that is burdened with its risks, the prevailing investment incentives will be suboptimal.

With this understanding of the dynamics of the financial market, together with the implied management incentives associated with these regulatory options, it is now possible to identify a preferred solution. While future GPU customers and future customers of other utilities may share indirectly in the benefits of such a project, their benefit share is quantitatively small. For example, to the extent that the TMI investment serves to advance generation technology, all future customers would benefit. Similarly, the use of nuclear energy for today's customers preserves, to a degree, petrochemical resources for future use. However, when such indirect benefits are compared with the $500 million cost-of-service savings, it becomes apparent that the dominant share of such a project's benefits accrue to current GPU customers. Hence, the interest of preserving correct investment-management incentives is best served if the regulatory process results in current GPU customers sustaining the dominant share of these residual costs — the risk-benefit principle.

The residual costs of the TMI accident would be inconsequential to the 86 million customers nationally that benefit from nuclear power, but for the 1.5 million Pennsylvania and New Jersey customers GPU services the short-run impact may imply additional social costs.[2] In effect, present institutional options may not permit the risk-benefit principle to operate. While the final data are not in, it may be expected that the proportioning of these residual costs between customer and investor will be more the result of expediency, rather than the exercise of regulatory principles for assuring correct investment incentives.[3]

Recommendation for the Future

This article has identified a framework for the exercise of informed regulatory judgement. In addition to structuring the problem, this discussion of the financial aftermath of the TMI accident has revealed a generic institutional weakness that deserves further comment.

In unregulated industries, investment risks are naturally accommodated by the dynamics of a freely operating financial market. Subjecting the investor both the downside risk of an investment failure and the upside benefit of an investment success produces a risk versus benefit balance. However, the symmetry which fosters this risk versus benefit balance is effectively preempted by the ratchet effect of the regulatory process; by assuring that the benefits of investment successes accrue to customers, the utility industry investor is not protected by these natural financial market dynamics.

This article has recognized that normal operation of the regulatory process provides a substitute for these natural financial market dynamics, yielding a relatively secure investment return. But the TMI accident has shown that catastrophic events may excessively stress the function of this institution, rendering it non-operational; i.e., the economic dislocations potentially associated with required rate increases may be socially unacceptable. The failure of this system, and the resultant imposition of additional risk on the financial community, produces a cost-of-capital impact throughout the industry and on all future customers.

Understood in this way, the suggested resolution of the generic problem manifested by the TMI events is apparent. Institutional arrangements should be constructed to provide a secure mechanism for correctly dispersing such costs — according to the risk-benefit principle. An insurance program to recover investment-carrying charges and replacement power costs while a plant is out of service would provide an auxiliary buffer to protect utility investments. Such insurance should assure that current beneficiaries underwrite current risks, thus avoiding financial market distortions and preserving the efficiency of investment incentives in this industry.

More specifically, in appreciation that 86 million customers nationally benefit from nuclear power, the risks associated with this technology should be directly underwritten by this beneficiary group. Revenue contributions to such an insurance program should be correlated with a current benefit, cost-of-service measure. That is, customers who save the most from nuclear power should pay the most to this insurance program.

Such an institutional modification will come too late to accommodate the financial problem presently being experienced by GPU, its customers and stockholders, and the industry. The regulatory challenge of 1979 is to resolve the TMI question, *within existing institutions*, in a manner that minimizes present and future social costs.

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[2] Nineteen seventy-seven total customers of central stations. (Source: Edison Electric Institute.)

[3] In recognition of the potential for economic dislocations of its customers, the company has recommended a sharing of these residual costs among shareholders, employees, and customers.

Exhibit Two

STATEMENT BY THE EDISON ELECTRIC INSTITUTE

AN OVERVIEW OF THE FINANCIAL DIFFICULTIES
OF THE
ELECTRIC UTILITY INDUSTRY
AND THEIR IMPACT ON THE FUNDING OF NECESSARY FUTURE CONSTRUCTION

PRESENTED BY

H. L. CULBREATH
PRESIDENT
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BEFORE THE HOUSE SUBCOMMITTEE
ON
ENERGY CONSERVATION AND POWER

April 6, 1981

An Overview of the Financial Difficulties of the Electric Utility Industry and Their Impact on the Funding of Necessary Future Construction

The electric utility industry has a unique role to play in the revitalization of the U.S. economy. It supplies the energy form most conducive to increasing productivity in both the industrial and service sectors and represents the main mechanism for harnessing plentiful domestic coal and nuclear resources in order to reduce energy imports. It also represents the key link to the future world of alternative energy sources which in most instances will be tapped to produce electricity or will evolve in a symbiotic relationship with electricity. Unfortunately, the ability of the industry to fulfill its critical responsibilities is being compromised by a number of financial problems, many of which stem from the ways regulation is affecting the industry's expansion plans and the level of its prices under current inflationary conditions.

Regulation's part in the present predicament is two-fold. On the one hand, mandated fuel use practices plus delay and uncertainty engendered by environmental regulations and nuclear licensing procedures have been big contributors to cost increases. On the other hand, failure of rate regulation to respond to cost increases by granting adequate and timely rate relief has caused such a deterioration in the industry's ability to earn a fair return on its investment that additional financing is often impossible and, when it is possible, it can only be done by imposing heavy costs on existing shareholders and customers.

Regulation, though a major factor in the industry's financial decline, has not been the only problem. Equally important are the increasingly inflationary nature of the U.S. economy and the inability of the economy to generate adequate savings for productive investment. Tax policies which have favored consumption over investment are at the origin of these latter difficulties.

The serious nature of the industry's financial problems is clearly seen in the data set forth in the Appendix to this paper. The erosion of earned return on equity and the steady rise in interest costs are clearly evident. By reducing interest coverage these two trends have made further debt financing a frequent impossibility. Moreover, recent rises in interest rates to unprecedented levels are effecting what may be permanent changes in long-term financial markets to the detriment of capital intensive industries. And consequent efforts to expand equity capital have been hindered by, and contributed to, the decline of market to book values for utility shares.

Construction Commitments and Requirements (1981-1990)

The investor-owned electric utility industry is currently committed to an expansion program involving some 150,000MW of essentially coal and nuclear capacity. Of this total 134,000MW is scheduled for commercial service within ten years. Non-investor-owned systems have another 40,000MW of capacity on order and firmly scheduled for commercial operation, 36,000MW of which should be generating power by the end of 1990.

The total of 190,000MW covering all sectors of the industry represents an increment equivalent to about 30% of installed capacity at year end 1980 and to about 45% of 1980's record peak load of 438,000MW. The present program contrasts with the all time forward commitment of 312,000MW which existed in utility planning schedules at year end 1974. That figure, at that time, represented 66% of the year end 1974 capacity total and 90% of the 1974 summer peak.

As evidenced by the dramatic shrinkage in forward commitments outlined above, electric utilities have sought to adjust as rapidly as possible to both reduced growth rates and increasing financial difficulties. This adjustment process since 1974 has entailed cancellation of some 66,000MW of steam generating capacity, exactly offsetting the 66,000MW of new orders placed since 1974 and effectivel meaning that the industry has made no net new commitments to capacity expansion in the last 6 years. Of equal importance has been the effec of deferrals. For example, in the first nine months of 1980, 60 generating units totalling 59,000MW had their scheduled commercial operation dates postponed by at least one year.

Serious concern is justified by this continuous contraction of the industry's construction program. Since 1974, peak load growth has averaged 3.9% per year with yearly increases ranging from 1979's 0.9% to 1980's jump of 6.5%. Because a similar growth can be expected in the coming decade, 1990 will see a demand of about 640,000MW. A minimum 25% reserve margin would require an installed capacity of 800,000MW, or 185,000MW above year-end 1980's levels. But present schedules, already slipped many times and likely to be slipped further, call for only 170,000MW to be put in place by the end of 1990. Furthermore, the effective capability of a plant may not be as great as the name plate capacity. In recent years capability has averaged 3 to 5% less than name plate capacity.

Reliability problems, inherent in the current march of events, cannot be avoided if the industry's financial situation does not improve markedly. Unfortunately, coming restrictions on gas use imposed by Section 301 of the Fuel Use Act and continuing uncertainty over nuclear licensing are acting to increase the industry's capital requirements and making it less and less likely that even current commitments to new capacity will be maintained.

Investor-Owned Electric Utility Construction Expenditures and Financial Requirements (1981-1990)

Despite a steadily contracting forward commitment to new generation capacity, the pressure of rising inflation rates has continued to drive annual construction expenditures upward. Edison Electric Institute projects that for the ten-year period 1981-1990, outlays on electric plant and equipment by investor-owned utilities will total $265 billion. This estimate, which is based on forecasts supplied by a sample of companies representing 30% of investor-owned electric revenues, incorporates an estimated average inflation rate of 9%, suggesting that real expenditures will fall at over 2.5% per year. About 40% of the projected outlays can be generated internally if rate relief continues to be granted at a relative pace similar to that of 1980.

This would leave $220 billion to be raised externally, of which around 30% would be in the form of common stock.

It is important to note that non-investor-owned electric utilities will also be facing large capital requirements over the coming decade. Normally, their construction expenditure totals range from 1/4 to 1/ those of investor-owned companies. Thus, the entire electric utility industry will be expending from $455 to $485 billion by 1990.(1)

Construction Requirements in the 1990's

Current financial problems besetting the electric utility industry have significance not only for the decade immediately ahead but for the last ten years of the century as well. In this regard it is important to understand that these present problems, if not resolved, will effectively preclude the new construction commitments which are absolutely necessary for the maintenance of reliable service in the 1990's. It is likewise important to understand that the maintenance of reliable service after 1990 will require considerable new construction even if growth in electricity demand is at a very low annual rate.

Why these additional construction commitments will have to be made can be illustrated by considering the "Low Growth" scenario described in EEI's Economic Growth in the Future-II study. This scenario would result in zero growth in total primary energy use over the period 1978-2000. Such a zero energy growth future would permit a GNP growth of only 1.7% per year. Nevertheless, electricity requirements would grow by 2% per year and require having approximately 820,000MW of installed capacity in the year 2000. While this is only 205,000MW more than 1980's year-end total, to achieve even this low figure by the end of the century will necessitate the construction of over 400,000MW of new facilities. Why? Because at least 100,000MW of existing generating capacity will have reached 40 years of age during the next 20 years and need to be retired. And, because over 45,000MW of gas burning capacity will have to be replaced prematurely if the provisions of Section 301a of the Power Plant and Industrial Fuel Use Act remain in force. In addition over 50,000MW of oil burning steam generating facilities which cannot be converted to coal should be replaced in keeping with the National policy to reduce dependence on foreign energy sources.

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(1) Capital expenditures for electric plant and equipment by the total electric utility industry should account for about 10% of all non-residential fixed investment over the 1981-1990 period, given the present constraints on capital raising faced by the industry. Should the industry's financial position be improved sufficiently to allow the start of construction needed for the 1990's, this figure could rise to the range of 12-15%.

The magnitude of this capacity expansion requirement even with a very low growth outlook is more than twice the figure now on order, i.e., 400,000MW vs. 190,000MW. Without a marked improvement in its ability to raise capital it is questionable whether the industry can maintain its present forward commitment let alone fund any new capacity additions.

The Economy's Need For Expanded Generation Capacity

Doubts about the industry's ability to meet even low load growth in the 1990's should cause serious concern because the situation described above is accompanied by an annual GNP growth of less than 2%. Such a low rate of economic expansion, according to recent analyses by the Electric Power Research Institute (EPRI), will not permit the various groups of a given age and educational level in our society to achieve in the future the same real income levels that similar age groups now enjoy. In other words, a 50 year old with a high school education in the year 2000 will have, on average, a lower real income than a 50 year old with a high school education today. To maintain the real income levels of each age/education group will necessitate economic growth of at least 2.5% yearly. Such a pace of economic expansion would, according to EEI's analysis, require net electric capacity growth of 2.7% per year through 2000, leading to an installed capacity in that year of 1,010,000MW or 400,000MW more than in 1980. Given the replacement requirements outlined above, the total new capacity which would have to be put in place by 2000 would exceed 600,000MW, more than 3 times the present forward commitment of 190,000MW.

If our society should seek to go beyond mere maintenance of present age/education income levels and strive to achieve the kind of economic growth that would significantly improve the country's social and energy situations, namely 3.0% per year, electricity requirements would have to grow by 4.3% per year and net capacity by 3.8% to reach an end-of-century figure of 1,285,000MW or 675,000MW above today's total. With over 200,000MW of replacement needed, the construction burden which would confront the utility industry in this case would be 4-1/2 times the present commitment.

Cogeneration As A Partial Alternative

One of the frequently cited alternatives to relieve financial demands on electric utilties is the expansion of industrial cogeneration. And indeed, as a primary energy saver cogeneration has many attractions for both electric companies and users of process steam and hot water. Consequently, utilities throughout the nation are actively pursuing possible arrangements with industrial firms. However, even a rapid expansion of industrial cogeneration financed by the industrial firms themselves would have only a marginal impact on the utilities' capital problems.

The limited impact likely to result from industrial cogeneration can be appreciated from the following example. If we assume a 10% per annum average increase in industrial production of power over the next 20 years, the output from industrially-owned power plants in 2000 would equal some 510 billion Kwhr.(1) A capacity factor of 75% would mean that this level of production would require around 77,000 MW of industrial capacity, 60,000MW more than existed in 1980.(2) However, as was noted in the previous section, some 400,000MW of utility capacity will have to be constructed by the turn of the century even to accommodate a "low electricity, zero energy growth" scenario.

What kind of investment requirement would face industrial electricity producers were they to bear the full cost of the cogeneration expansion outlined here? At over \$800 per KW for the kind of equipment likely to be installed, some \$50 billion in current dollars would be the amount of capital which industrial firms would have to muster in addition to the capital required to maintain or expand their regular lines of business.[1]

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(1) In 1980 industrial generation represented about 75 billion Kwhr or roughly 3.5% of total electricity supply in the United States. A growth rate of 10% annually would signify a healthy development of cogeneration.

(2) At year end 1980, U.S. industrial firms had 600 MW of thermal generating capacity on order and a little over 17,000MW in operation.

Despite Federal tax credits for investments in cogeneration and regulations issued pursuant to PURPA Section 210 which are intended to stimulate industrial firms to develop the market for cogeneration, industrial involvement in cogeneration has proceeded rather slowly.

Recent surveys cite a number of reasons why industrial firms may be reluctant or not able to build cogeneration systems.[2] For large industries, cogeneration may be a feasible option to pursue. However, small industries for the most part, tend to lack the capabilities, systems, and resources necessary for their own development of cogeneration potential. Small firms may also encounter considerable difficulty in securing adequate financing for the purpose of constructing a cogeneration facility. Their corporate managers may not be easily convinced to assume the financial risk which accompanies any investment which falls outside of the firm's main stream of investment. In addition, managers may not be willing to devote scarce management resources to the task of addressing the many technical, economic, financial, and legal aspects of bringing a cogeneration facility "on line."

Utilities on the other hand, already possess such resources as part of their overall management structure and may more easily restore the financial health of the industry so that the application of their talents can facilitate implementation of cogeneration. Some legislative and regulatory changes are required as well, in order to provide an equal, competitive business opportunity for utilities.

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[1] The $800/KW is an estimate based on installation of combined cycle equipment.

[2] Potential of cogeneration in Pacific Gas & Electric's Service area between 1980 and 1990, Volume I results prepared by Resource Planning Associates, Inc.

Load Management

There are many load management strategies and alternatives at the disposal of utility management which presently have a de minimus effect on current construction projections for the utility industry. Some of the load management practices which have received popular support from utilities are:

- o Remote control of residential customers' air conditioners, and electric water and space heaters to allow the devices to be "cycled" on and off during peak-demand periods;
- o Time of use optional rates to shift demand to off-peak periods;
- o Energy-conservation audits of commercial customers to lower total consumption, to shift demand to off-peak periods, and to identify alternative energy sources; and
- o Minimum energy efficiency appliance ratings.

At the present time, there is still a great deal of uncertainty concerning the performance, consumer acceptability, and cost effectiveness of these approaches. The experiences of a number of utilities currently testing and demonstrating these approaches will help to remove some of the uncertainty. Recently Duke Power Company announced that its load management programs have reduced its winter peak demand by 769 megawatts and its summer peak demand by 546 megawatt

Present Financial Conditions

The deteriorated state of the investor-owned utilities financial position is evident from the many indicators described in the Appendix to this paper. It is sufficient, however, to examine only a few salient measures in order to see the difficulty confronting these utilities as they attempt to fund the next ten years' construction. Among the most critical measures are:

- return on equity
- interest rates on new debt issues
- AFUDC as a percent of net income
- internal funds generation as a percent of construction expenditures

In 1980 earned return on equity fell to 11%, although state regulatory commissions, in rate cases decided during the year, authorized equity returns averaging 14.2%. More importantly, electric utilities filing new applications for increases during the year sought returns ranging from 16 to 18%. This extreme discrepancy between what is needed and what can be earned in the face of today's inflation is the major reason why utility stocks are currently selling at less than 75% of their book values.

The inadequency of equity returns is highlighted by the gap between them and the cost of new debt. In 1980, new long-term debt was issued at interest rates averaging nearly 14%. Thus a negative risk premimum of 3% was realized while the equity markets were demanding just the opposite, a 3 to 4% return differential over long-term interest rates.

Another key indicator of the industry's financial trouble is the portion of net income accounted for by AFUDC. In 1980 the share climbed to an estimated 46%. Three years earlier in 1977 the comparable figure was 30%. As a result of the steady increases in AFUDC's part in net income, the dividend pay out by electric utilities since 1974 has exceeded the cash component of net income. The steady erosion of the cash content of utility income has reduced the ratio of internal funds generation to construction expenditures. In 1980 this ratio dropped below 28%. As recently as 1976 it had been 40%.

The rising share of AFUDC in net income and the decline in internal funding of its construction program stems from inadequate rate relief and the inability of the utility industry to get new plants into service. This latter problem is becoming particularly acute because of regulatory delays that prevent the operational licensing of nuclear facilities. At the end of 1980 investor-owned electric construction work in progress (CWIP) accounted for 30% of net electric plant, and equalled close to $65 billion. It is estimated that about 2/3 of this total was in nuclear facilities. Moreover, the current investor-owned expenditure rate on nuclear plants of $10 billion per year is causing the CWIP total to balloon at an accelerating rate. In both 1979 and 1980 the industry's CWIP account rose by the equivalent of half of all construction outlays. This is a matter of growing seriousness because, effectively, in most jurisdictions no cash return can be earned on funds immobilized as CWIP. The fact that an ever-growing share of the industry's investment is prevented from earning a cash return underlines the importance of putting CWIP in rate base and having the associated carrying charges reflected in rates charged for electric service.

Possibilities for Federal Action

Federal action must be addressed to all aspects of the utilities financial problem. In the case of licensing delays and excessively restrictive environmental regulations, federal measures can have a direct and immediate impact. In the case of steps which must be take to directly improve utility finances, federal actions are needed in the areas of fuel use and taxation as well as in the area of rate regulation where measures are needed which will aid state utility commissions in coming to grips with the financial issue. The major initiatives recommended by Edison Electric Institute to improve utility financial health are outlined below.

Recommendations

I. Fuel Use and Licensing

A. Section 301a of the Power Plant and Industrial Fuel Use Act should be repealed. This provision's requirement that electric utilities cease the burning of natural gas after 1989 can impose a replacement capacity construction burden on this industry which will cost at least $55 billion. Moreover, the burden will fall mainly on utilities in 5 states which are experiencing growth faster than the national average and thus have heavy construction obligations simply to meet demand, without having to replace usable capacity.(1) If unable to construct replacement capacity, the electric utilities affected by 301a would have no choice but to burn imported oil. Such additional oil requirements could equal 800 thousand barrels/day.

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(1) Texas, Oklahoma, Kansas, Arkansas and Louisiana.

B. Expedite the granting of operating licenses for nuclear stations now under construction. At present there are 63 nuclear generating units under construction by investor owned utilities and scheduled for operation by 1990. These units vary from 1% to 100% complete. At the end of 1980 it is estimated that the total construction work in progress (CWIP) represented by these partially completed facilities exceeded $40 billion, equivalent to an average of $650 million per unit. The investment commitment represented by these projects cannot, in most cases, be abandoned without the utility incurring costs greater than those required to complete the units.(2)

Failure to complete these nuclear plants would also have other cost consequences for the nation including increased oil imports of from 700 thousand to 1.4 million barrels/day by 1990.(3) A year's delay in licensing a nuclear unit now adds $150 million to the plant's cost.

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(2) Total electric CWIP for investor owned utilities exceeded $60 billion at year end 1980, equal to 30% of the industry's total capitalization.

(3) Based on a rate of growth of electricity requirements ranging from 2% annually to 4.3% per year. In each instance the oil use cited would account for about one half of the lost nuclear generation. Coal and power shortages would account for the other half.

In 5 years such a delay will have become a matter of a quarter billion dollars. Replacement energy for a unit not entering service can range currently from $75 million to $300 million/year depending on the alternative fuel source. By the mid-1980's these costs will have risen also to a possible range of $100 to $600 million per year for each nuclear unit not being licensed as scheduled. In addition, electricity shortages of significance could appear in several areas.

II. Taxation

Legislation should be developed which would:

A. defer taxation on reinvested dividends until the stock thus acquired is sold.

B. preserve normalization requirements for investment tax credits and the benefits of liberalized depreciation.

C. accelerate capital cost recovery including depreciation of CWIP which is included in rate base while maintaining normalization requirements and the priori [illegible] tilization of investment tax credits.

D. provide for current tax deductions for the estimated costs of decommissioning nuclear plants and handling spent nuclear fuel when such costs are included in the cost of service.

E. extend the incentive of energy tax credits to the electric utility industry.

F. expand the availability of tax exempt bond financing to help finance specific projects in concert with the national interest, e.g. coal conversion, and remove restrictions on the use of tax exempt bonds for financing required pollution control at nuclear power plants.

G. extend TRASOP investment credits beyond 1983.

H. remove obstacles to greater offshore debt financing by eliminating withholding taxes on interest payments to qualified foreign bondholders.

III. Rate and Financial Regulation

A. By its own actions in these areas the Federal Government should set an example for and encourage state regulatory bodies to consider, in generic hearings, adoption of the following measures:

- using forward test periods to determine rate base and expenses for ratemaking
- authorizing rates of return on equity which reflect the total risk (financial and regulatory) that the share-holder is being asked to shoulder
- including construction-work-in-progress in the rate base, and reflecting in the approved rates the full carrying charges on the capital invested in construction projects
- allowing depreciation rates which reflect the need to recover capital more rapidly in the present inflationary environment
- permitting normalization of the benefits of accelerated depreciation and investment tax credits

- permitting the use of fuel adjustment clauses which enable utilities to recover fully the cost of all fuel used for power production under both normal and emergency conditions

B. Both the Federal Power Act and the Public Utility Holding Company Act should be amended to permit more innovative approaches to the financing of power facilities.

C. The Federal Energy Regulatory Commission (FERC) should give consideration to the endorsement of the general concept of joint generating corporations, such as the New York State ESPRI proposal, whose rates are set on the basis of a cost of service tariff.

D. The FERC should, as a general rule, include CWIP in rate base.

E. The FERC should rationalize its filing and review procedures with the objective of disposing of wholesale electric rate cases within 12 months. However, the broad goal of expedition in the ratemaking process does not necessarily require adoption of a single generic rate of return or the use of any specific rate of return calculation technique by FERC or any State Regulatory Commission with respect to the companies subject to its jurisdiction.

F. The FERC should develop and publish a policy regarding suspensions of rates which permits, to the maximum extent possible, utilities to collect rates which ultimately are likely to be justified. (See "Suggestions of Edison Electric Institute for reconsideration of suspension policy." October 21, 1980)

G. FERC should establish rates and set rates of return based on the economics of the wholesale operation in question and not based on actions taken or not taken by state regulatory authorities with retail jurisdiction over the wholesaling utility.

H. The FERC should take a formal policy position against any proposals made in FERC proceedings that any newly constructed projects may be excluded from rate base on the basis of an after-the-fact finding of lack of need.

I. The FERC should encourage ratemaking policies which facilitate project financing of desirable utility innovations, such as the conversion of facilities to coal use. Both ratepayers and the sponsoring utility benefit from such arrangements.

Solutions to the financial problems besetting electric utilities lie essentially with state regulatory commissions, but actions at the federal level like those outlined above are necessary if state authorities are to be able to resist the pressures acting to hinder the granting of adequate rates. In generic terms the solutions which must come from the various states are essentially identical. However, because of different circumstances in different states, the exact nature of steps to be taken in each of the listed areas may differ from jurisdiction to jurisdiction, but the principles remain the same, namely, to have rates for electric service which fully reflect the capital costs involved in providing the service and which provide sufficient cash flows to enable the utility to complete existing and/or undertake new construction needed to meet the requirements of its customers while pursuing the national goal of reduced dependence on oil imports.

Establishing targets in each of these areas is again something which must be done taking account of the circumstances prevailing in each jurisdiction. However, some logical benchmarks should be used by regulatory commissions in analyzing the adequacy of their actions. These would include:

- enabling a utility to earn a return on common which exceeds by a reasonable risk premium the cost of new long-term debt amd permits achievement of a bond rating that does not constrain the company's access to any capital sources
- enabling a utility to market new equity at a price no lower than book value
- facilitating a cash flow equal to at least 50% of construction expenditures
- making possible a common equity ratio of at least 40%

Progress towards these objectives will be signaled by major improvements in several indicators. These will include:

- a rising earned return on equity accompanied by a decline in Allowance for Funds Used During Construction (AFUDC) as a percent of net income

- rising interest coverage ratios calculated excluding AFUDC
- a rising percentage of construction covered by internally generated cash
- an increase in the effective tax rate paid by utilities as their real earnings rise
- a rising market to book ratio for utility common stock
- a rising share of common equity in the total capital structure
- a declining dividend payout ratio needed to maintain investor interest and a concommitant rise in the share of retained earnings in the capital structure
- improvement in bond ratings

Other Measures Benefiting the Financial Situation of Electric Utilitie

In addition to administrative and legislative actions targeted specifically on problems affecting utility finances, a host of other steps needed to aid the economy as a whole will have particularly beneficial side effects on utilities. These additional measures can be generally grouped under two headings: (1) fighting inflation and (2) promoting saving and investment.

Fighting Inflation

Reducing federal budget deficits and reducing the burden of general regulation of business are probably the most effective short term moves against inflation. To the extent that they are successful, interest rates will decline and costs throughout the economy will be lower. A one percent decline in interest rates currently can save electric utility customers nearly $200 million a year. And, reducing by one-half the burden of general regulation of business, estimated at near 5% of GNP, could save electric utility consumers more than $1.5 billion annually(4).

Promoting Saving & Investment

Encouraging saving and investment is the key to solving America's basic long-term economic problems of productivity stagnation and inflation. Only through new investment in plant, equipment, and infrastructure can U.S. productivity growth be resuscitated and production costs lowered. Also, it will be essentially through investment in new machinery, housing and vehicles that energy conservation will be affected, not through the retrofitting of old facilities.

However, realizing greater investment will require instilling a new sense of economic confidence in the citizenry. No businessman or individual will undertake major long term investments, even though the means be available, if he does not believe his market or employment has a future. Creating this kind of confidence depends on consistent policies favoring long term economic growth.

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(4) Based on the assumption that the reduced cost burden would be reflected uniformly in the prices of all input goods and services purchased annually by investor owned electric utilities.

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(4) Based on the assumption that the reduced cost burden would be reflected uniformly in the prices of all input goods and services purchased annually by investor owned electric utilities.

Table 1

Total Capital Expenditures
Electric Utility Industry
1969 - 1990

The industry anticipates a construction program totaling $365 billion during the period 1981-1990. This is about 170 percent of the total net electric utility plant in existence at the end of 1980. It is questionable whether this is an achievable goal, given the industry's current weak financial condition.

Table 2

Capital Expenditures as a Percent
of Total Capital Investment
1969 - 1980

Capital expenditures as a percent of average capitalization have ranged from 12 to 13-1/2 percent during the last five years. The large sizes of the industry's construction program relative to its capitalization is at a level thought by some to be unmanageable. Based on a survey undertaken in April of 1980, 66 utilities representing over 82 percent of the industry's operating revenues indicated that 1981 construction expenditures as a percent of total 1980 year-end capitalization would reach 14.3 percent.

Table 3

Comparison of Authorized Return on Common Equity
and Earned Return on Common Equity
Electric Utility Industry
1974 - 1980

There was continued deterioriation in the return earned on common equity in 1980. The earned return declined from 11.3 percent in 1978 to 11.1 percent in 1979 and 11.0 percent in 1980. The gap between average authorized return and realized return increased to about 3.2 percentage points although there has been a dramatic drop in the average regulatory lag from the 11-1/2 months for 1979 to 8-3/4 months in 1980.

Table 4

Capitalization and Capitalization Ratios
Electric Utility Industry
1969 - 1980

From the high debt level established in 1970 of 55.3 percent of total capitalization, the industry has steadily reduced its debt ratio. In 1980 it was 50.1 percent. The reduction in debt's share of capitalization is essential if the industry is to protect its interest coverages which declined significantly in 1980. The industry currently is rated between AA and A.

Table 5

Internal Generation of Funds As A Percent
of Construction Expenditures
Electric Utility Industry
1969 - 1980

Internal generation of funds (excluding AFUDC) in the early 1960's provided almost 60 percent of the industry's needs for its construction program. Today it provides less than 30 percent and poses a problem for the industry should the anticipated construction programs continue.

Table 6

AFUDC As A Percent of Net Income
Before Preferred Dividends
Electric Utility Industry
1969 - 1980

AFUDC (a non-cash item) as a percent of net income continues to increase, a disturbing factor for companies attempting to finance completion of their base load generating plant expansion programs. There are many utilities now deriving over 50 percent of their earnings from AFUDC. More than 45 percent of the industry's net income in 1980 was due to AFUDC. This was more than 2-1/2 times the average of 1970.

Table 7

Interest Coverage
1969 - 1980

After the low point in 1974 interest coverage improved until 1978 when coverage turned lower and in 1980 declined significantly to a level approaching that of 1974. As already noted there were 14 bond downgradings during 1980, twice the number experienced in 1979.

Table 8

Electric Utility Senior Debt Rating Changes by Moody's
1971 - 1980

Table 9

Comparison of Short-Term Debt Outstanding To Total Capitalization
1969 - 1980

In the past decade short-term debt as a percent of total capitalization ranged between 2.3 - 4.0 percent with the one exception of 1974 when it stood at 5.6 percent. Although short-term debt increased significantly in 1979 over the previous three years, the ratio stayed within the range experienced during the past decade. However, the constraints on long-term financing which have emerged in 1980's turbulent market conditions have probably pushed the short-term ratio to a higher level than was recorded in 1979. It is estimated that at least 50 percent of the short term debt reflects the issuance of commercial paper by electric utilities.

Table 10

Average Market Price to Book Value
1969 - 1980

Investor disenchantment with the electric utility stocks is evidenced by the continuing decline in the market price to book value reported as of February 27, 1981, to 71 percent. This compares with 78 percent at year-end 1979 and 107 percent at year-end 1976.

Table 11

Annual Dividend Increases
Moody's 24 Electric Utilities
1969 - 1979

Dividends increased 6 percent in 1979 over 1978. However, the increases still haven't kept pace with the rate of inflation. The payout rate climbed to 74 percent in 1979 compared with 71 percent in 1978 and 67 percent in 1969. The question which must be asked is whether the industry can consider anything higher than that level as an industry payout ratio.

Table 12

Dividends As a Percent of Book Value
1974 - 1980

Dividend yields have had to be raised to maintain investor interest to the extent that the yield per book value is now over 9 percent. This high rate reflects our high payout ratio and the fact that less earnings are being retained. And at the same time we have a dilution of book value because of selling new common below book value.

Table 13

Electric Utility Rate Applications and Approvals
1970 - 1980

During 1980 electric utilities filed rate increase applications totaling $10,871 million, almost double the $5,736 million filed in 1979. Rate increase approvals during 1980 totaled $5,932 million, more than double the $2,853 million in 1979.

It would be appear that the regulatory authorities are beginning to understand the financial plight of many of the electric utilities.

Table 14

Composition of New Long-Term Investor-Owned
Electric Utility Industry Capital Sources
1969 - 1980

Table 15

Comparison of Embedded Interest Rates
Average Yield on Newly Issued Bonds
and Percent Return on Common Equity
1965 - 1980

The spread between the average embedded interest rate on long-term debt and earned return on average common equity continues to narrow. Unless the earned return on equity can be increased to maintain an appropriate spread between embedded costs of debt and return on equity, the industry will find itself in an untenable financial position as coverage ratios decline further, making it impossible for many utilities to raise outside capital.

Table 1

Total Capital Expenditures
Investor-Owned Electric Utilities
1969 - 1990
(Millions of Dollars)

Year	Total Capital Expenditures
1969	$ 8,294
1970	10,145
1971	11,894
1972	13,385
1973	14,907
1974	16,350
1975	15,090
1976	16,979
1977	19,758
1978	22,393
1979	24,378
1980	25,720
Projected*	
1981	28,000
1982	29,000
1983	31,000
1984	32,000
1985	35,000
1986-1990	210,000

Source - 1969-1979, EEI Statistical Year Book for 1979, Table 50.
Projections by EEI Staff
*Assumes approximate 9 percent inflation rate

Table 2

Capital Expenditures as Percent of Total Capital Investment
1969 - 1980
(Millions of Dollars)

ear	Capitalization at Year end	Average Capitalization	Electric Capital Expenditures	Capital Expenditures As Percent of Average Capitalizatic
1980 E	$207,850	$199,582	$ 25,720	12.89%
1979	191,313	182,546	24,378	13.35
1978	173,779	167,235	22,393	13.39
1977	160,690	153,577	19,758	12.87
1976	146,463	139,679	16,979	12.16
1975	132,895	126,155	15,090	11.96
1974	119,415	113,485	16,350	14.41
1973	107,555	102,235	14,907	14.58
1972	96,915	91,506	13,385	14.63
971	86,096	81,140	11,894	14.66
1970	76,183	71,812	10,145	14.13
1969	67,441	64,730	8,294	12.81

Sources: 1971-1979, EEI Statistical Year Book for 1979, Tables 50 & 51
1969-1970, EEI Historical Statistics of the Electric Utility Industry Through 1970, Tables 50 & 51.

Table 3

Comparison of Authorized Return on Common Equity
and Earned Return on Common Equity
Investor-Owned Electric Utility Industry
1974-1980

Year	Average Authorized Return	Earned Return
1974	12.5%	10.6%
1975	12.9	11.1
1976	12.8	11.5
1977	13.1	11.4
1978	13.2	11.3
1979	13.4	11.1
1980 Est.	14.2	11.0

Source: EEI

Based on rate decisions made during the year.

Table 4

Capitalization and Capitalization Ratios - Investor-Owned Electric Utilities
1969-1980
(Millions of Dollars)

	Preferred Stock		Long Term Debt		Common Capital Stock Capital Surplus Earned Surplus		
	Amount	% of Total	Amount	% of Total	Amount	% of Total	Total Amount
1969	$ 6,360	9.5%	$37,127	55.0%	$23,954	35.5%	$ 67,441
1970	7,466	9.8	42,164	55.3	26,553	34.9	76,183
1971	9,157	10.7	47,122	54.7	29,817	34.6	86,096
1972	11,335	11.7	52,024	53.7	33,556	34.6	96,915
1973	12,939	12.0	56,910	52.9	37,706	35.1	107,555
1974	14,740	12.3	63,612	53.3	41,063	34.4	119,415
1975	16,852	12.7	69,927	52.6	46,116	34.7	132,895
1976	18,384	12.6	75,827	51.8	52,252	35.6	146,463
1977	20,019	12.5	81,985	51.0	58,686	36.5	160,690
1978	21,565	12.4	87,488	50.3	64,726	37.3	173,779
1979	23,881	12.5	96,258	50.3	71,174	37.2	191,313
1980 E	25,700	12.4	104,150	50.1	78,000	37.5	207,850

Sources: 1971-1979, EEI Statistical Year Book for 1979, Table 55
1969-1970, Historical Statistics of the Electric Utility Industry Through 1970, Table 55.

Table 5

Internal Generation of Funds As a Percent of Construction Expenditures Investor-Owned Electric Utility Industry 1969-1980 (Millions of Dollars)

Year	Internal Generation of Funds Excluding AFUDC	Construction Expenditures (a)	Percent Internally Generated
1969	$2,909	$ 8,830	32.9%
1970	2,906	10,734	27.1
1971	3,206	12,485	25.7
1972	3,686	14,120	26.1
1973	4,127	15,691	26.3
1974	4,388	16,991	25.8
1975	5,615	15,361	36.6
1976	7,002	17,547	39.9
1977	7,602	20,313	37.4
1978	7,641	22,943	33.3
1979	7,405	25,202	29.4
1980 E	7,340	26,600	27.6

(a) Includes other utility plant of Combination Companies

Table 6

AFUDC as a Percent of Net Income
Investor-Owned Electric Utility Industry
1969-1979

Year	AFUDC (Millions of $'s)	Net Income (a) (Millions)	AFUDC as % of Net Income
1969	$ 405	$ 3,130	12.9%
1970	594	3,333	17.8
1971	822	3,774	21.8
1972	1,095	4,356	25.1
1973	1,297	4,851	26.7
1974	1,596	5,146	31.0
1975	1,694	6,002	28.2
1976	1,896	6,990	27.1
1977	2,367	7,813	30.3
1978	2,907	8,574	33.9
1979	3,727	9,302	40.1
1980 E	4,750	10,250	46.3

(a) Before Preferred Dividends

Source: EEI

Table 7

Interest Coverage
Investor-Owned Electric Utility Industry
1969-1980 Year End

Before Federal Income Taxes

Year	Interest Coverage Including AFUDC	Interest Coverage Excluding AFUDC
1969	3.73	3.51
1970	3.11	2.85
1971	2.94	2.63
1972	2.96	2.60
1973	2.79	2.43
1974	2.46	2.11
1975	2.66	2.33
1976	2.84	2.50
1977	2.93	2.54
1978	2.89	2.46
1979	2.67	2.20
1980 E	2.57	2.09

Table 8

Electric Utility Senior Debt Rating Changes by Moody's 1971-1980

Year	Number of Ratings	
	Lowered	Increased
1971	3	1
1972	3	1
1973	2	3
1974	25	1
1975	15	2
1976	9	0
1977	2	3
1978	4	1
1979	6	3
1980	14	1

Source: White Weld & Co., Salomon Brothers

Table 9

Comparison of Short-Term Debt
As A Percent of Total Capitalization
Investor-Owned Electric Utility Industry
1969-1980
(Millions of Dollars)

Year	Total Capitalization	Short-Term Debt	Total	Short-Term Debt as % of Total
1969	$ 67,441	$2,809	$ 70,250	4.0%
1970	76,183	2,671	78,854	3.4
1971	86,096	2,808	88,904	3.2
1972	96,915	3,188	100,103	3.2
1973	107,555	4,362	111,917	3.9
1974	119,415	7,133	126,548	5.6
1975	132,895	4,646	137,541	3.4
1976	146,463	3,380	149,843	2.3
1977	160,690	3,792	164,482	2.3
1978	173,779	4,038	177,817	2.3
1979	191,313	7,320	198,633	3.7
1980	Not yet available - 3/29/81.			

Table 10

Market Price to Book Value
Investor-Owned Electric Utility Industry
1969-1980

Year End	Moody's (a)	Salomon Brothers (b)
1969	132%	
1970	131	
1971	122	
1972	111	
1973	79	
1974	52	66%
1975	65	84
1976	74	107
1977	73	101 -
1978	63	86
1979	57	78
1980	Na	73
1981 (February 27)	Na	71

(a) Based on 24 electric utilities.

(b) Based on 100 electric utilities, data for 1974 and 1975 by EEI based on 70 electric utilities.

Table 11

Dividend Increases By Years
Moody's 24 Electric Utilities
1969-1980

Year	Dividends/ Shares	Percent Increase Over Prior Year
1969	$4.63	-%
1970	4.73	2.16
1971	4.81	1.69
1972	4.92	2.29
1973	5.04	2.38
1974	4.83	(4.17)
1975	4.99	3.31
1976	5.25	5.21
1977	5.68	8.19
1978	5.98	5.28
1979	6.34	6.02
1980	Na.	Na.

Table 12

Dividends As A Percent of Book Value
Investor Owned Electric Utility Industry
1974-1980

Year	Market To Book	Yield	Yield Per Book
1974	65%	12.45%	8.09%
1975	89	8.70	7.74
1976	107	7.73	8.27
1977	101	8.20	8.28
1978	86	9.77	8.40
1979	78	11.24	8.77
1980	73	12.44	9.08

Source: Dean Witter Reynolds 1974-1975; Salomon Brothers, 1976-1980

Table 13

Electric Utility Rate Application Filings and Approvals 1974-1980 (Millions of Dollars)

Year	Applications Filed	Approvals
1970	$ 797	$ 533
1971	1,368	826
1972	1,205	853
1973	2,125	1,089
1974	4,555	2,229
1975	3,973	3,094
1976	3,747	2,275
1977	3,953	2,311
1978	4,494	2,419
1979	5,736	2,853
1980	10,871	5,932

Source: EEI

Table 14

Composition of New Long-Term External
Capital Sources
Investor-Owned Electric Utility Industry
1969-1980
(Millions of Dollars)

Year	Long Term Dept Amount	%	Preferred Stock Amount	%	Common Stock Amount	%	Total Amount
1969	$3,727	76.9%	$ 373	7.7%	$ 744	15.4%	$ 4,844
1970	5,460	69.2	1,015	12.9	1,411	17.9	7,886
1971	5,234	58.8	1,602	18.0	2,063	32.2	8,899
1972	4,312	49.7	2,103	24.3	2,252	26.0	8,668
1973	4,866	54.4	1,539	17.2	2,548	28.4	8,953
1974	7,772	67.8	1,743	15.2	1,948	17.0	11,458
1975	6,517	54.3	2,121	17.7	3,374	28.0	12,012
1976	6,200	53.4	1,567	13.5	3,837	33.1	11,604
1977	7,389	56.6	1,873	14.3	3,793	29.1	13,055
1978	6,868	57.9	1,671	14.1	3,317	28.0	11,856
1979	7,223	56.1	2,289	17.8	3,356	26.1	12,868
1980	7,847	56.4	2,003	14.4	4,063	29.2	13,913

Source: EBASCO Services, Inc.
Excludes ESOP, TRASOP and Dividend Reinvestment common stock disbursements.

Table 15

COMPARISON OF EMBEDDED INTEREST RATES, AVERAGE YIELD ON NEWLY ISSUED BONDS, AND PERCENT RETURN ON COMMON EQUITY INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY 1965-1980

Year	LONG-TERM DEBT AVERAGE IMBEDDED INTEREST RATE PERCENT	AVERAGE INTEREST RATE ON NEW LONG-TERM DEBT PERCENT	RETURN ON AVERAGE COMMON EQUITY PERCENT
1965	3.8%	4.61%	12.5%
1966	3.9	5.53	12.7
1967	4.1	6.07	12.7
1968	4.3	6.80	12.3
1969	4.6	7.98	12.2
1970	5.1	8.79	11.8
1971	5.5	7.72	11.6
1972	5.7	7.50	11.7
1973	6.0	7.91	11.5
1974	6.5	9.59	10.6
1975	6.9	9.97	11.1
1976	7.1	8.92	11.5
1977	7.3	8.43	11.4
1978	7.5	9.30	11.3
1979	7.8	10.85	11.1
1980 E	8.4	14.00	11.0

OVERVIEW OF THE FINANCIAL DIFFICULTIES
OF THE
ELECTRIC UTILITY INDUSTRY
AND THEIR IMPACT ON THE FUNDING
OF NECESSARY FUTURE CONSTRUCTION

I. Current Situation

- Although few new commitments are being made, investor-owned electric utilities still face $365 billion of construction in 1981-1990. This equals 170% of 1980 year-end capitalization.
- Earned return on equity now down to 11%, more than 3% below average level authorized by state commissions in 1980.
- AFUDC accounted for over 45% of the industry's net income. This was 2½ times the average of 1970.
- Construction Work in Progress (CWIP), at year-end 1980, exceeded $60 billion, and was equal to 30% of capitalization. Two-thirds of CWIP was in nuclear plants.
- Internal generation of funds (excluding AFUDC) fell to 28% of construction expenditures in 1980.
- Interest coverage moved still lower in 1980. Coverage before income taxes was 2.57 including AFUDC and only 2.09 excluding AFUDC.
- According to Moody's, 14 electric utilities had their senior debt downgraded in 1980, compared to only 6 in 1979.
- Short term debt rose by $3.3 billion in 1979 to a level equal to nearly 4% of total long term capitalization. In 1980 the level rose again.
- Market to book for electric utility common stock fell to 0.71 at the end of February, 1981 compared to 0.78 in 1979.
- The spread between the earned return on common and the embedded interest rate declined to less than 3% in 1980. (11% vs. 8.4%)
- The spread between the earned return on common and the average interest rate on new long term debt became negative. (11% vs. 14%)

Finally, a positive note . . . .

- Rate increase approvals during 1980 totaled a record $5.9 billion, more than double the $2.9 billion granted in the comparable period of 1979.

II. What Can the Federal Government Do to Help to Improve This Situation:

We are recommending action in 3 specific areas:

- A. Fuel Use and Licensing
- B. Taxation
- C. Rate and Financial Regulation

Our major suggestions:

Under Fuel Use & Licensing

1. Repeal section 301a of the Fuel Use Act - this could save $55 billion in capital outlays required to replace perfectly good plant or avoid increasing imported oil use by 600,000 barrels per day.
2. Accelerate operational licensing of completed nuclear plants. Currently, delays mean up to $150 million per unit per year in increased plant costs and up to $300 million per year in additional costs for replacement power.

Cogeneration

Remove current legislative and regulatory disincentives in order to proved an equal, competitive business opportunity for utilities. Particular recommendations will be presented at the hearings this Committee will be conducting later relative to utilities role in cogeneration.

Under Taxation

1. Defer taxes on reinvested dividends.
2. Preserve normalization requirements.
3. Accelerate capital cost recovery including depreciation of CWIP if in rate base, but maintain priority use of ITC.
4. Provide for current tax deductions for estimated costs of nuclear decommissioning and handling spent nuclear fuel.
5. Extend incentive of energy tax credits to electric utilities.
6. Extend availability of tax exempt financing for national interest projects, e.g., coal conversion, also for pollution control at nuclear plants.
7. Extend TRASOP credits beyond 1983.
8. Eliminate withholding taxes on interest payments to qualified foreign bondholders.

Under Rate and Financial Regulations

1. FERC should encourage state commissions to hold generic hearings to consider:
    - Using forward test periods.
    - Authorizing returns on equity which reflect the real risk borne by shareholders.
    - Including CWIP in rate base.
    - Increasing depreciation rates to reflect today's inflationary situation.
    - Normalizing tax benefits.
    - Permitting use of fuel adjustment clauses to recover costs of fuel for both normal and emergency operations.
2. Amend Federal Power Act and Public Utility Holding Company Act to permit greater flexibility in financing.
3. FERC should give consideration to the endorsement of the general concept of joint generating corporations.
4. FERC should include CWIP in rate base.
5. FERC should complete wholesale rate cases in 12 months.
6. FERC should develop and publish a policy regarding suspensions of rates which permits, to the maximum extent possible, utilities to collect rates which ultimately are likely to be justified.
7. FERC should base its decisions solely on merits of the wholesale case in question and not on actions taken (or not taken) by the state commission which has retail jurisdiction.
8. FERC should take a formal policy position against any proposals made in FERC proceedings that any newly constructed projects may be excluded from rate base on the basis of an after-the-fact finding of lack of need.
9. FERC should endorse state commission ratemaking policies which facilitate project financing of desirable utility innovations, such as the conversion of facilities to coal use.

III. In Addition to Utility Specific Measures, the Federal Government Must:

- Fight inflation in the short term through reduced budget deficits and eliminating the cost burdens of unnecessary regulations.
- Fight inflation in the long term by promoting savings and investment.
- Reinstill a sense of economic confidence in the citize by adopting consistent long term policies which openly favor economic growth.

Exhibit Three

STATEMENT BY EDISON ELECTRIC INSTITUTE
RECOMMENDED LEGISLATIVE AND REGULATORY CHANGES TO PROMOTE COGENERATION DEVELOPMENT

Summary

EEI believes that cogeneration has a potentially important and beneficial role in our nation's energy future. We support cogeneration as a means of facilitating this nation's transition from an energy economy based on cheap, abundant supplies of oil and natural gas to an era where the use of scarce and imported fuels is restrained, and increasing use is made of energy conservation.

However, EEI believes that a number of recent legislative and regulatory initiatives have had the effect of discouraging the full potential development of cogeneration by not providing an equal, competitive business opportunity for electric utilities and equitable treatment for their ratepayers and shareholders.

The recommended legislative and regulatory changes which we believe will contribute to our national energy goals include:

- Amending Section 201 of PURPA (P.L. 95-617) to allow utilities to own more than 50 percent of a cogeneration facility and be eligible for the rate and exemption privileges of a qualifying facility.

- Providing equal treatment to electric utilities with respect to cogeneration tax incentives under the Energy Tax Act of 1978 (P.L. 95-618) and Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223).

- Amending FERC regulations to implement PURPA in a manner which recognizes the full range of purchase rates permissible under Section 210 of PURPA. The purchase rate established should be just and reasonable based on negotiations between the utility and qualifying facility, but at no time should the rate be greater than 90 percent of true full avoided costs.

- Granting exemptions from the Fuel Use Act for new cogeneration facilities only where there is a showing of net oil/gas savings.

STATEMENT BY EDISON ELECTRIC INSTITUTE

RECOMMENDED LEGISLATIVE AND REGULATORY CHANGES TO PROMOTE COGENERATION DEVELOPMENT

PRESENTED BY

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BEFORE THE HOUSE SUBCOMMITTEE

ON

ENERGY CONSERVATION AND POWER

APRIL 27, 1981

STATEMENT BY EDISON ELECTRIC INSTITUTE
RECOMMMENDED LEGISLATIVE AND REGULATORY CHANGES TO PROMOTE COGENERATION DEVELOPMENT

I. INTRODUCTION

Mr. Chairman and members of the Committee, I appreciate the opportunity to appear before you to discuss the subject of cogeneration and, in particular, the issue of equal treatment for electric utility ownership of cogeneration facilities. I am Ralph C. Mitchell, III; Vice President, Conservation & Renewable Resources for Arkansas Power & Light Company, (AP&L), Little Rock, Arkansas, and Chairman of the Edison Electric Institute (EEI) Issue Group on Cogeneration and Small Power Production which is a group of electric utility representatives formed to monitor legislative and regulatory developments in cogeneration and small power production. This testimony is presented on behalf of both AP&L, which is one of the operating companies of the Middle South Utilities System, and also on behalf of the EEI.

Cogeneration has a potentially important and beneficial role in our nation's energy future. EEI supports cogeneration as a means of energy conservation wherever it will reduce the nation's dependence upon oil and natural gas. It believes that the goal of our nation's energy policy is to facilitate the transition from an energy economy based on cheap, abundant supplies of oil--much of which is imported--and natural gas to one in which the use of scarce and imported fuels is restrained and increasing use is made of coal and other domestically energy resources, as well as energy conservation. In some cases, cogeneration can assist in satisfying this national goal. However, the current legislative and regulatory environment is not conducive to the most effective and efficient deployment of cogeneration technology. A number of recent legislative initiatives and associated regulatory policies have had the effect of either prohibiting or discouraging the particpation of electric utilities in the promotion and development of cogeneration. These legislative and regulatory disincentives are numerous and should be removed to provide an equal, competitive business opportunity for electric utilities and equitable treatment for their ratepayers and shareholders.

In examining the benefits of equal competitive opportunities for utilities, the potential role of cogeneration without utility participation needs analysis. Industrial investment in cogeneration is not the sole nor optimal way to fulfill cogeneration's potential role in our nation's future energy mix. In recently conducted meetings with 33 major steam-using industries in the AP&L service territory, these industries, it was found, are fully aware of the desirability of cogeneration from a fuel use efficiency standpoint and are familiar with the incentives provided by the Congress to encourage its development. However, major cogeneration investment commitments by the industries are unlikely for at least one of three reasons.

First, an industrial company--like any other entity--has finite capital resources available. Such an industry prefers to use its limited available capital for investments which will expand its production capacity or reduce the unit cost for its primary business product. The long-term survival of any business depends upon its having adequate and competitive productive capacity available to serve its market; quite frankly, at present many of American industries have difficulty accumulating sufficient capital to satisfy this primary objective. In the cases in which an industrial firm does have adequate capital resources, investments in cogeneration must compete with all other investment opportunities on the basis of overall profitability to the company. Many have found that the payback period for cogeneration exceeds the firm's criteria for the commitment of new capital investments, especially for industries in which energy costs are a small proportion of total production cost.

Second, many industrial firms are reluctant to pursue cogeneration due to a lack of managerial, technical, operating and/or environmental skills available in its organization for the development of a cogeneration project. This is especially true if the company is considering a solid fuel, such as coal, or a synthetic fuel. And, it is also a particularly important factor for medium and smaller size firms.

A third, and very significant, deterrent to industrial cogeneration is the finite increments of air and water quality available, as well as land resources. Again, an industrial company would prefer to use these limited resources to pursue its primary line of business, and not in power generation--most especially fuel burning power generation.

My own findings have been confirmed by recent conversations with other utility executives. In particular, I would call this Committee's attention to a recent study of the industrial cogeneration potential in the Pacific Gas & Electric Company (PG&E) service area. In presenting the findings of a survey of PG&E's industrial customers, the consultant's report concluded:

> Cogeneration is an ancillary investment for most companies because it is not directly related to staying in business. When companies make capital budget decisions, investments needed to maintain or increase production capacity recieve top priority. These investments have

> the most immediate impact on the company's growth and profitability. If manufacturers are to continue their rapid growth rate and maintain profitability, a majority of all capital must be devoted to these investments. As a result, cogeneration and similar investments have second priority. While these investments can help to improve overall profits, they are not essential to the company's continuing operations. For example, several companies in PG&E's service area have profitable cogeneration potential but low overall energy costs. Consequently, they will not invest in cogeneration, because it would have little effect on their profits.*

Based on results such as these, the potential for industry-financed cogeneration to meet the aforementioned goals of national policy is severely limited.

The limited potential for industrial investment in cogeneration, suggests the alternative benefits of providing equal competitive ownership opportunities for utilities. First, utility expertise and experience in the capital markets is advantageous for the future deployment of cogeneration technologies. As EEI testified before this Committee on April 6th , as a primary energy saver, cogeneration has many attractions for both electric utilities and users of process steam and hot water. Consequently, electric utilities throughout the nation are actively pursuing possible arrangements with industrial firms. However, even a rapid expansion of industrial cogeneration financed by the industrial firms would not have a significant impact on utility financial problems. The current financial problems of utilities will gradually improve, allowing them to finance new generating capacity which is the most cost effective. Even in the immediate future, utilities need to invest in new capacity such as coal and nuclear to meet load growth in regions with inadequate reserve margins or in regions where reduction in the use of oil and gas for electricity generation is imperative. Allowing utilities equal competitive investment opportunity with respect to cogeneration which reduces scarce fuel use will help to ensure that future capital investments (both central station and dispersed energy facilities) are made in the most cost-effective manner. Utilities can then access capital markets to deploy cogeneration where it is in the interest of the ratepayer and the shareholder. Utilities also have the expertise and experience to arrange project financing for cogeneration facilities, using capital from a wide variety of sources.

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*Resource Planning Associates, Inc. Potential of Cogeneration in PG&E's Service Area Between 1980 and 1990, prepared for Pacific Gas & Electric Company, San Francisco, CA, December 1980.

Second, since cogeneration is an ancillary investment of industrial concerns, investors frequently require cogeneration projects to be more profitable than their essential projects. The PG&E survey found that the minimum acceptable return on investment for industrial cogeneration projects is usually over 25%. Because electricity production is the main business for electric utilities and because electric utilities are accustomed to longer pay back periods, investors may accept a lower rate of return. Thus, allowing equal competitive ownership would increase the attractiveness of cogeneration to the investment community.

Third, incentives for utility ownership of cogeneration may benefit small industrial or commercial concerns. While such a small user might not find it economical or feasible to invest in cogeneration alone, a third party might find it advantageous to cogenerate for a cluster of smaller users. Utilities, relying on their knowledge of small users and technical expertise, would be the ideal facilitator for such cogeneration projects.

Finally, electric utilities can provide the systems and resources capable of more effective integration of cogeneration and other dispersed energy technologies into their centralized systems. In designing a cogeneration system to serve a particular industrial steam requirement, an electric utility would no doubt optimize electrical output and its reliability to the utility's grid. An industrial firm does not have the same incentive to maximize the benefits of a cogeneration facility to the electric utility system, and thus the public.

Utilities have two additional characteristics important to the development of cogeneration: First, experience with the operation of coal and other type boilers, environmental protection equipment, fuel procurement and handling, and waste disposal; and second, unique knowledge of the energy consumption patterns of their customers and a frequent contact with them. This experience and knowledge should be utilized. Consumer confidence in the technical abilities of utilities, as well as their permanence, make them an ideal institution to promote the development of cogeneration.

Thus, where cogeneration is a cost-effective means of promoting energy conservation that would meet our national energy goal of reduced reliance on imported oil, the public interest would best be served by removing legislative barriers and disincentives to utility participation in the cogeneration market. The specific issues requiring revision are the inequality of treatment under the Public Utilities Regulatory Policies Act (PURPA) of 1978 with respect to utility ownership of cogeneration facilities and equal treatment with respect to energy tax credits for electric utility-owned cogeneration projects. If these two barriers to competitive utility ownership of cogeneration are removed, an electric utility could provide all of the benefits of cogeneration to an industrial steam user and remove three disadvantages perceived by industry: capital constraints, skills availability, as well as environmental/ land limitations. The industrial community broadly supports this concept.

In the following sections, the EEI position on these critical issues is presented and certain principles it supports are discussed with two other cogeneration issues: the avoided cost concept and certain Fuel Use Act ramifications relative to cogeneration.

II. EQUAL TREATMENT FOR ELECTRIC UTILITY-OWNED COGENERATION

The regulations issued by the Federal Energy Regulatory Commission (FERC) pursuant to Section 201 of the Public Utilities Regulatory Policies Act (PURPA) of 1978 grant "qualifying facility" (QF) status to cogeneration and small power production facilities which are less than 50% utility-owned. QF status entitles cogenerators to a number of rate and regulation exemption privileges. FERC regulations implementing Section 210(e) of PURPA exempt QFs from state regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I and Part II, Sections 210-212), and from the Public Utility Holding Company Act. In addition, QFs are entitled to sell excess power to utilities at avoided cost rates and purchase back-up power from utilities at nondiscriminatory rates.

Cogeneration facilities which are more than 50% utility-owned do not qualify for these benefits. As such, utilities continue to have their wholesale rates regulated by FERC and their retail rates subject to state rate regulation. In addition, utility-owned cogenerators are subject to the prohibitions and requirements of the Public Utility Holding Company Act. As pointed out in the following paragraphs, these restrictions provide a strong disincentive to utility cogeneration development.

There are two main reasons an electric utility cogeneration entity must have the same incentives that PURPA provides for an industrial-owned facility. First, the industrial firm is clearly interested in steam at a competitive cost. Since there are two revenue streams to the cogenerator--electricity and steam sales--the price paid for the electrical output is a major determinant of the cost for the steam output. Therefore, if an industrial-owned facility sells its electrical output to the utility system at avoided cost, but a utility-owned cogeneration facility receives less than avoided cost for electrical output, the electric utility would necessarily have to price the steam at a higher and consequently less competitive rate. Second, if the rate of return is regulated for a utility-owned facility and unregulated for an industrial-owned facility then it is likely that given a choice between these two entities, an investor would seek the investment that provides the higher return on capital. This is particularly true given that the industrial cogenerator has a guaranteed market for its electrical product under PURPA reducing risk for the industrial investor. Thus, utilities are at a competitive disadvantage in attracting investment capital for cogeneration projects.

The Energy Tax Credit (ETC), which is available with respect to cogeneration property, is not allowed for "public utility property." However, a utility cogeneration facility with is "qualified" under the PURPA regulations might not be considered "public utility property" as defined in Treasury Reg. S1.46-3(g)(2) in that such property is not regulated in the traditional cost of service manner. Therefore, a public utility may only be able to take advantage of the ETC if it owns 50% or less of a cogeneration facility. Any restriction on utility ownership percentages acts as a disincentive for utilities interested in cogeneration and should be removed. Further, the tax benefits applicable to owners of "qualified cogeneration facilities" should be made available to utilities on an equal basis.

III. EQUAL TREATMENT WITH RESPECT TO TAX CONSIDERATIONS

Although this Committee exercises no jurisdiction over tax code changes, any discussion of electric utility ownership of cogeneration facilities requires brief mention of the Energy Tax Act of 1978 (P.L. 95-618) and the Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223). The Energy Tax Act of 1978 provided a general exclusion from the Energy Tax Credit for property which is owned or leased by a public utility. In the Crude Oil Windfall Profit Tax Act (IRC Section [48(1)(17)]), property which would otherwise qualify for an additional ETC will not qualify if it is public utility property. Such property includes solar, wind, biomass, recycling, and cogenerating equipment. Many kinds of property to which the public utility exclusion applies are directly related to the function of generating electricity; this exclusion is specifically applicable to cogeneration equipment as defined by the Crude Oil Windfall Profit Tax of 1980 (IRC Section [48(1)(14)]). Cogeneration facilities provide for energy conservation by utilizing an additional form of energy which would otherwise be wasted. Ownership of cogeneration facilities by utilities, as well as nonutilities, should be encouraged. Accordingly, if tax incentives are available for non utility owners of cogeneration facilities, they should also be extended to utilities. In that the conservation offered by cogeneration can be quite substantial when applied to industrial uses, applying tax credits equally to utility and nonutility owned cogeneration facilities would be appropriate if it would contribute to reducing our dependence on scarce fossil fuels.

IV. THE AVOIDED COST CONCEPT

As discussed in the following paragraphs, whether or not utilities are afforded an equal competitive opportunity with industrials, a proper balance must be struck between the interest of ratepayers and developers of cogeneration projects. As this Committee is well aware, on February 19, 1980, the Federal Energy Regulatory Commission issued its Order No. 69 which constituted the Final Rule regarding the implementation of Section 210 of PURPA. Essentially, FERC's final rules regarding Section 210 of PURPA specify that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the utility can avoid by virtue of such purchase. Under FERC rules, the rates established for cogenerators and small power producers will be determined by each state regulatory agency. The electric utilities are presently involved in or are preparing for state cogeneration tariff hearings, and are committed to working closely with the state regulatory authorities in this new area. However, no discussion of cogeneration incentives would be complete without addressing the "avoided cost" concept, and in particular its impact on cogeneration development.

FERC's concept of avoided cost does not restrict itself to short-run avoided costs or, essentially, fuel costs but instead addresses itself to all costs avoided by a utility as a result of purchasing power from qualified cogenerators and small power producers in lieu of generating additional power from its own present and/or future facilities or purchasing power from other utility systems. The actual level of costs avoided is dependent on the reliability of power purchased from qualifying facilities, duration of purchases, and the load and capability characteristics of the purchasing utility over the time period encompassing the purchase. It must be emphasized that the "avoided cost" may vary significantly depending on seasonal considerations, ~~and~~ that the "avoided cost" in one season will be different from that in another season. For example, in the case of AP&L, this difference is due to the fact that during the hot summer months, a purchase of energy and/or capacity from a cogenerator may displace oil-fired peaking units. However, this same purchase during other seasons may displace coal-fired or nuclear generation resulting in a lower purchase price in that the costs avoided by the utility are less. Obviously, the factors which cause this difference in "avoided cost" will vary depending on the circumstances of a particular utility, and upon the power pool to which it is connected.

It is clear from the "reasonable and nondiscriminatory" standard outlined in Section 210 of PURPA that ratepayers of a utility should not subsidize cogenerators and small power producers. Thus, it is imperative that the ratepayers should be made no worse off by virtue of a utility's purchase of power from a cogenerator than would have been the case if the utility instead generated this power itself or purchased the power from another utility system. The measurement of costs foregone or avoided due to a utility's purchase of power from a cogeneration or small power production facility is, therefore, crucial to the assurance that ratepayers are not, in fact, subsidizing such facilities.

The situation of a utility building to meet neither peak demand nor total energy requirements, but instead to reduce the total cost of service, may not yield a situation of avoided capacity costs. Each utility system must be evaluated on a case by case basis to determine if avoided capacity costs are applicable. Only by such an evaluation can a determination of "true avoided costs" be made (i.e. an accurate time related avoided cost) taking into consideration the individual factors affecting a particular utility. FERC has attempted in its rules issued under Section 210 of PURPA to provide the maximum possible incentive to industry to invest in cogeneration. While the utility's full avoided cost may provide the maximum permissible incentive to industrial cogeneration investment under PURPA 210, EEI does not believe that this approach is "just and reasonable" in every case. The essence of the "just and reasonable" standard of PURPA should be a balancing of the interests of the affected parties, which are typically the cogenerator, the ratepayer and the shareholder. In the context of PURPA Section 210, FERC is directed among other matters to weigh the interests of utility consumers for reliable, reasonably priced electricity against the benefits of cogeneration. Yet there may be situations under which the full avoided cost rule precludes this required balancing. EEI believes that a rate which is below "true avoided cost", but still above the cogenerator's cost, often will suffice to induce industrial investment in cogeneration and at the same time benefit the utility ratepayer.

Put simply, if industries could be encouraged to cogenerate at a level of compensation which is less than the utility's true full avoided cost, then the ratepayer would benefit in the form of reduced future costs of energy. If a lower level of compensation would achieve the same result (i.e. reduction of oil imports), then any further compensation is not required. A lower level of compensation to cogenerators would mean lower rates for ratepayers.

Summarizing, EEI believes the interest of ratepayers could be best-served by ensuring that utilities do not have to pay more than the minimum level of compensation required by industries to encourage their positive action toward cogeneration. EEI proposes one alternative more accurately to carry out the intent of Section 210 of PURPA, amending PURPA so that qualifying facilities would be compensated for the sale of energy at a rate negotiated by the utility and the cogenerator up to a maximum rate equal to 90% of "true avoided costs." Such an approach is consistent with the "just and reasonable" standard of PURPA in that it allows the utilities' ratepayers to be able to share the benefits of cogeneration and small power production. Support by the public for the development of cogeneration would certainly be an admirable objective. It is one thing to state to the ratepaying public that based upon a true time-related avoided cost you are no worse off in your electricity cost then you otherwise would be from the development of cogeneration. It is far more persuasive honestly to assure ratepayers that their costs are actually lower than would be the case absent cogeneration.

V. FUEL USE CONSIDERATIONS

The Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C.A. S.8301 et seq. ("the Act") prohibits the use of oil and natural gas to certain new and existing major fuel burning installations consisting of a boiler and powerplants, including cogenerators, unless an exemption is granted for such use by the Economic Regulatory Administration of the Department of Energy. Sections 212(c) and 312(c) of the Act provide exemptions from its prohibitions on oil and gas use upon a finding that a petitioner has demonstrated that "economic and other benefits of cogeneration" are unobtainable unless petroleum or natural gas, or both, are used in the facility. Interim rules have been issued to implement these sections of the Act (44 Fed. Reg. No. 97). Also, final rules have been proposed under Docket No. ERA-R-80-24 which would have the effect of easing the restrictions on the use of oil and natural gas for cogeneration facilities. EEI feels that any exemption from the Act's restrictions on the use of oil or natural gas for new cogeneration facilities should be conditioned on the facility demonstrating a net savings of oil or gas over its useful life. Such a regulatory approach will ultimately maximize the benefits of the energy efficiency of cogeneration by reducing the nation's dependence on the use of scare fossil fuels.

While the current business of the utilities is the generation, transmission and distribution of electric energy, they have a dedicated interest in and a strong commitment to developing synthetic fuels technologies and determining ways these fuels can provide an even more efficient application of cogeneration. Therefore, we view with serious concern the means proposed to accomplish the removal of disincentives to cogeneration. The proposal to provide permanent exemptions for the use of natural gas and oil in new cogeneration facilities (without a showing of net savings of oil and gas) poses a very real danger to the continuing interest in and the economic viability of the development of cogeneration based on other fuel sources. The proposed exemptions, by seeming to favor entrenched and resource-limited oil and natural gas cogeneration technologies, could seriously retard and may even frustrate alternate fuels development and production through encouraging the erosion of a principal segment of future markets.

EEI believes that the Fuel Use Act exemption approach for use of oil and natural gas in new cogeneration applications is appropriate with the proviso that there be net savings of oil or gas. This approach is consistent with the intent of the Fuel Use Act and with the national energy policy objectives of reducing our reliance on scarce fossil fuels.

VI. CONCLUSION

The legislation and regulations which preclude or discourage a utility from directing its expertise to and investing its capital in cogeneration facilities are not consistent with our national energy goals and tend only to delay the development of an economy which is not overly dependent on scarce fuels for most all its energy needs. To preclude or discourage a utility from investing in cogeneration facilities only tends to further inhibit the development of an important technology for meeting the nation's energy conservation potential. The recommended legislative and regulatory changes which we believe will contribute to our national energy goals include:

- Amending Section 201 of PURPA (P.L. 95-617) to allow utilities to own more than 50% of a cogeneration facility and be eligible for the rate and exemption privileges of a qualifying facility.
- Providing electric utilities equal treatment with respect to cogeneration tax incentives under the Energy Tax Act of 1978 (P.L. 95-618) and Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223.)
- Amending FERC regulations to implement PURPA in a manner which recognizes the full range of purchase rates permissible under Section 210 of PURPA. The purchase rate

established should be just and reasonable based on negotiations between the utility and qualifying facility, but at no time should the rate be greater than 90% of true full avoided costs.

- Granting exemptions from the Fuel Use Act for new cogeneration facilities only where there is a showing of net oil/gas savings.

EEI believes that these legislative and regulatory initiatives will assist the nation to more rapidly achieve its goal of energy independence.

Table One

Table 1
Summary of Results
Business Diversification Survey

Type of Venture	Number of Ventures	Percent of Total	Operational	Planned	Inactive	Subsi-diaries	Regulated	Jurisdiction**	
								State	Federal
1. Fuel Exploration and Development	75	30%	72	0	3	67	36	25	25
2. Real Estate	31	13%	30	0	1	24	3	2	1
3. Energy Conservation Services	22	9%	16	5	1	5	2	2	0
4. District Heating	15	6%	12	2	1	2	1	1	0
5. Cogeneration	14	6%	8	6	0	2	1	1	0
6. Appliance Sales/Leasing/Service	13	5%	13	0	0	0	-	-	-
7. Fuel Transportation/Transloading	11	4%	11	0	0	10	9	1	8
8. Load Management Controls	9	4%	9	0	0	1	1	0	1
9. Aquaculture	7	3%	6	1	0	1	0	-	-
10. Customer Billing/Collection Services	4	2%	4	0	0	2	0	-	-
11. Project Management/Engineering/ Consulting Services	4	2%	3	1	0	2	0	-	-
12. Solar/Renewable Product Sales	4	2%	2	2	0	0	-	-	-
13. Synfuels Projects	4	2%	1	3	0	4	2	2	1
14. Equipment Wholesaling	3	1%	3	0	0	3	0	-	-
15. Waste Product (Ash) Sales	3	1%	3	0	0	0	-	-	-
16. Energy Education Services	3	1%	3	0	0	1	1	0	1
17. Materials Testing/Quality Control	2	1%	2	0	0	1	1	-	1
18. Thermal Storage Projects	2	1%	0	2	0	1	0	-	-
19. Water Rights/Storage	2	1%	2	0	0	2	2	2	1
20. Water Sales/Distribution	2	1%	2	0	0	2	2	2	0
21. Computer Software Sales	2	1%	2	0	0	1	0	-	-
22. Commercial Paper Sales	2	1%	½	0	0	0	-	-	-
23. Telphone/Telecommunications	2	1%	2	0	0	2	2	2	2

-OVER-

	Type of Venture	Number of Ventures	Percent of Total	Operational	Planned	Inactive	Subsi-diaries	Regulated	Jurisdiction**	
									State	Federal
24.	Timber Harvesting	1	*	1	0	0	1	0	-	-
25.	Word Processing	1	*	1	0	0	0	-	-	-
26.	Recreation Area/Marina	1	*	1	0	0	1	0	-	-
27.	Rail Car Maintenance	1	*	1	0	0	1	0	-	-
28.	Short Line Railway	1	*	1	0	0	1	1	1	1
29.	Manufacturing-Earth Drilling Equipment	1	*	1	0	0	1	0	-	-
30.	Manufacturing-Heating Equipment	1	*	1	0	0	1	0	-	-
31.	Earth Drilling Services	1	*	1	0	0	1	0	-	-
32.	Collier Construction/Operation	1	*	1	0	0	1	1	0	1
33.	Aircraft Sales/Maintenance	1	*	1	0	0	1	1	0	1
34.	Graphic Arts/Exhibit Display	1	*	1	0	0	1	0	-	-
	TOTALS	247	100%	219	22	6	143	66	41	44

NOTES: * Less than one percent of total.
**Jurisdiction in which venture is regulated. Refers only to economic or service regulation.
Ventures may be regulated by either State or Federal governments, or both.

Mr. **Fuqua**. Thank you.

Mr. Roe.

Mr. **Roe**. Mr. Chairman, I will also summarize my written remarks both in the interests of time and because the two previous witnesses covered a lot of ground I find myself able to agree with.

It is no secret that the financial condition of public utilities in this country has been deteriorating for some time. What is different this year is that the fact has begun to be widely noticed, and utilities asking for help have begun to plead in chorus.

They have a point. By the usual Wall Street indexes, the electric utility industry is a financial invalid, and the transfusion of dollars needed to get it out of bed and back to its own definition of healthy will be enormous. And, the argument usually goes, if the utilities don't get more money, they can't build new powerplants and will have to keep burning expensive oil.

Unfortunately, this answer to the problem—more money and more new powerplants—overlooks a very important fact. Building large, new, long-leadtime, capital-intensive powerplants is in large part what got the utilities into financial trouble in the first place. I think both Mr. Benore and Mr. Ferrar touched on that.

And as interest rates have gone up in the last 10 years and demand has gone down, utilities have seen more and more of their capital tied up in unfinished plants which, as Mr. Benore has described, has undermined their cash earnings and eroded the book value of their shares.

The costs of tying up that capital in half-finished plants has gone up with the interest rates, and the symptoms have reinforced the disease; as customers' bills have gone up to compensate for rising costs, customers' demand has gone down, and the completion dates for big projects under construction have therefore been postponed further, thus making the problem worse. If utilities get the transfusion of money that they are asking for, but then use it to start another round of large central-station powerplants, they will very quickly be back, suffering again from the same financial anemia.

Fortunately, this vicious cycle is not unbreakable. There is a solution, one that will permit energy growth and oil backout by utilities without incurring the financial risks of large, long-leadtime plants. The solution is one that most utilities have not thought about, but those few that have have found it very attractive. And it is available to all or nearly all of the country's utilities. The purpose of my testimony is to explain what it is, why it is financially attractive, and what some of the consequences for Federal policy might be.

Over the past 3 years a number of very thorough, detailed analyses have shown that specific utilities can meet all or nearly all of their own predicted growth needs, for the foreseeable future, without starting any large new central-station powerplants—if they invest their capital instead in a collection of alternative energy sources, including conservation in the form of increased end-use efficiency. And if they do make those alternative investments, the result will be the same energy yield, with at least the same reliability, in the same time frame, at lower cost both to the utility and to its ratepayers.

This, of course, is a very dramatic claim, and it suggests that utilities, in their concentration on nuclear and coal plants, have been ignoring a massive, cheap energy source. It is a claim I would not expect anyone to take on faith, least of all a responsible utility manager or Government official.

But what I can report to you is that the analyses that have shown this to be true, in several specific cases, have been attacked, cross-examined, run through with a fine-tooth comb, and challenged by the best experts utility money can buy—and they have proved to be sound. I have attached complete copies of four such studies to my testimony.

These analyses have had a very strong influence on utilities and on State energy policy in California, where I come from, and where the work has been focused, and they have been responsible for greatly increased utility interest in conservation investments, solar water heating investments, cogeneration, and the like. I expect that Commissioner Walker of the California Energy Commission will give you a more complete description later this morning.

Most recently, one such analysis was responsible for causing Pacific Gas & Electric Co. and Southern California Edison Co., two of the country's five largest utilities, to abandon their plans for the most expensive baseload coal plant ever proposed in the United States.

Late last year Southern California Edison announced a major shift of corporate policy toward investment in the alternative energy sources I have been discussing, and said that by 1990 it expected that 30 percent of its anticipated 6,000 megawatts of additional generation needs would be met by those alternative energy sources. That announcement was described by the Washington Post, in a lead editorial, as "a little bit like Richard Nixon recognizing Red China," which perhaps overstates the case; but, from a financial viewpoint, I think the recognition that these alternatives are an untapped source was at least as overdue.

Similar changes are underway in other States, spurred in every case by a factual analysis of the financial benefits of investing in alternatives rather than in large central-station plants. One conspicuous example is New England Electric System whose chairman you will hear from later this morning. A major attraction of such investments is simply that each individual unit tends to be small, and relatively quickly completed, so that investments enter the rate base with relatively short lag time. And the pace and direction of investments is extremely flexible, so that changes in need projections, either up or down, can be quickly accommodated. This is unlike the situation with large central-station plants, where once you start, you're stuck—even if the demand growth you originally planned for starts to melt away on you during construction.

The studies that I have been talking about that lead me to report this to you are very specific, looking at real-world utilities with immediate real-world needs and real-world costs, and speaking in the language of utility planners. It would be overreaching simply to extrapolate that the same results would obtain for every utility in every State. But there is one constant shown by the experience to date: Every time you look seriously at the economic potential for these alternatives, you find much much more than anyone expected, by orders of magnitude.

I should make one additional point about California. You may be assuming, as many experts do, that California's energy situation is very different from the situation in the Northeast, because California faces high growth and needs large amounts of new capacity, whereas the Northeast, as we all know, has too much capacity and faces the different problem of lowering generation which is fired by oil.

In fact, however, California is in very much the same position as I described for the Northeast. In the recent proceedings on the 2500 in Allen-Warner Valley coal plant, California's two largest utilities took the position that the plant was not needed for growth—the official State growth forecast is below 1 percent—and that the reason it had to be built was to back out oil. And you may not be aware that Southern California Edison burns more oil than any other utility in the country. The alternatives that were analyzed would, among other things, replace more oil more quickly than the utilities claimed was possible with the plant.

What does all this mean for Federal energy policy? First, it suggests that at least a large part of the new energy that electric utilities need is already within their reach, in a form that can let them keep growing and yet help restore their financial health by greatly reducing the risk which is presently associated with plant investment, and which Mr. Ferrar very accurately described. The obstacles to obtaining large enough amounts of this kind of energy have been greatly exaggerated, in my view, and the principal obstacle is simple lack of awareness due to an embarrassing lack of analysis.

Second, Federal energy policy over the last several years, taken as a whole, has served, I believe, primarily to distract attention from the most economically sound alternatives, by putting its primary stress, and primary dollar boost, on the massive central station option of nuclear power, and on massive centralized synthetic fuels technologies. To the extent it has supported smaller scale, renewable sources like conservation and solar, it has emphasized advanced, high-technology forms of these sources, and has conveyed the impression that they are experimental and many years from full-scale commercial development by utilities.

I think this remains the prevailing view and you heard it earlier this morning. But I submit that this, too, is a distraction. Even with renewable energy, DOE has succumbed to the high-technology fallacy, and encouraged utilities and the public to overlook the simpler, already developed technologies lying on the doorstep.

Of course, this is not to say that everything DOE has funded is useless or misleading—for example, it has played an important role in advancing the development and testing of wind generators—but simply to say the priorities have created an impression which has caused everyone in this business to overlook some very sound, very immediate potential investments.

Wind, I think, is a very good example of DOE's useful involvement. They have been very helpful in testing wind generators; but on the implementation side, which of course is the key, getting lots of utilities to build lots of wind generators, this has been neglected. And I can give you a good example from my own experience.

For example, in hearings last year in California, Pacific Gas & Electric Co.'s own wind expert testified that the company could count on having several hundred megawatts of cost-effective and reliable wind machines in its supply plan, and could confidently plan today for them to be available starting in 1985, if it simply undertook an accelerated testing program on existing wind machine prototypes. But, following DOE's footsteps, the company has proposed a slow testing program that, it claims, will not guarantee it a deployable wind machine that its planners can rely on in any significant amounts before 1990.

In the meantime, unnecessary new coal and nuclear plants continue to be proposed, despite their ever-increasing financial risks. Federal policy choices for the electric utility industry have a tendency to enforce the same counterproductive stress on large central station plants, to the exclusion of alternatives. A particularly stark example is the proposal currently being floated by Secretary Edwards that the Fuel Use Act be amended to focus on coal alone as the only fuel for oil back out, removing any requirement or incentive to consider alternatives, including the ones I have been discussing.

The experience I have been describing also suggests that a top priority for continued Federal participation in electric energy policy should be to help utilities, and their regulators in the 50 States, to analyze the alternative energy sources available in clear financial terms, through objective, side-by-side cost comparisons, in individual specific cases, and in full planning detail.

DOE could play an enormously useful role in facilitating such analysis, providing technical support to regulatory bodies, and stressing the importance of looking at currently available energy options in financial terms, as utility investment options. In addition to its research role—and I guess I part company with Mr. Ferrar on this point—it could take on a much more active demonstration and development role, acting among other things as a clearinghouse for information so that the wheel need not be perpetually reinvented by each utility who decides to take these options seriously—as is unfortunately now the case.

Some structural reforms of the utility industry that have been proposed, including relaxing the Utility Holding Company Act and allowing the creation of unregulated subsidiaries, are intended as ways to increase utility earnings for shareholders without having to apply for rate relief in the traditional manner.

The Environmental Defense Fund does not oppose such changes in principle, but we think it is important to stress that the real solution lies within existing institutions in their existing form, and that shuffling corporate boxes in search of tax or other advantages is one more distraction from the real solution: Yes; more money for the utilities, but spent not on more large central station plants, but on smaller scale, renewable energy sources which are more profitable, to the extent they are more profitable.

If unregulated entities are better at developing these sources, then turn them loose. But if the entities are utility subsidiaries, then the question arises why these forms of energy should be treated any differently from traditional forms, particularly if they are just as reliable and more profitable—because to the extent they are, letting the utility pursue them through an unregulated subsidiary is simply keeping the financial benefit of lower cost service away from ratepayers and redistributing it to shareholders. I realize the usual assumption about such forms of energy is that they are riskier than conventional plants, which is why you need an entity which is more willing to accept risks, but in many cases the reverse is true. As a utility investment, conservation is much surer to work than coal or nuclear, and much surer to produce utility revenues on schedule.

On the other hand, if the entities in question are independent third parties in a deregulated situation, then the profit will go to them and utility financial health will not improve. In any case, it seems to us that these issues are primarily for the individual States to resolve, and that, based on past experience, Federal involvement in electric energy policy runs a high risk of enforcing conformity and stifling innovation and diversity, a risk which is perhaps greater than the risk of Federal forbearance.

We urge the subcommittee to think in terms of a maximum of information and analytic assistance, and a minimum of policy enforcement, as the ideal Federal role.

Thank you very much.

[The prepared statement of Mr. Roe follows:]

ENVIRONMENTAL DEFENSE FUND

before the U.S. House of Representatives
Subcommittee on Energy Development and Applications,
Committee on Science and Technology

TESTIMONY OF ENVIRONMENTAL DEFENSE FUND

ON

UTILITY FINANCIAL PROBLEMS AND POTENTIAL SOLUTIONS

Presented June 23, 1981

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Before the Subcommittee
on Energy Development and Applications

TESTIMONY
OF
ENVIRONMENTAL DEFENSE FUND
ON
UTILITY FINANCIAL PROBLEMS AND POTENTIAL SOLUTIONS

Mr. Chairman and members of the subcommittee:

My name is David Roe, and I am co-chairman of the Environmental Defense Fund's energy program. Thank you for inviting me to testify here today.

It is no secret that the financial condition of public utilities in this country has been deteriorating for some time. What is different this year is that the fact has begun to be widely noticed, and utilites asking for help have begun to plead in chorus. They have a point. By the usual Wall Street indices, the electric utility industry is a financial invalid, and the transfusion of dollars needed to get it out of bed and back to its own definition of healthy will be enormous. And, the utilities argue, if they don't get more money, they can't build new power plants, and will have to keep burning expensive oil.

Unfortunately, this answer to the problem--more money, and more new power plants--overlooks a very important fact. Building large, new, long lead-time, capital-intensive power plants is in large part what got the utilities into financial trouble in the first place. As interest rates have gone up in the last ten years and demand has gone down, utilities have seen more and more of their capital tied up in unfinished plants, greatly undermining their cash earnings and thus eroding the book value of their shares. The costs of tying up that capital in half-finished plants has gone up with the interest rates, and the symptoms have reinforced the disease; as customers' bills have gone up to compensate for rising costs, customers' demand has gone down, and the completion dates for big projects under construction have therefore been postponed further, thus making the problem worse. If utilities get the transfusion of money that they are asking for, but then use it to start another round of large central station power plants, they will very quickly be back, suffering again from the same financial anemia.

Fortunately, this vicious cycle is not unbreakable. There is a solution, one that will permit energy growth and oil back-out by utilities without incurring the financial risks of large, long lead-time plants. The solution is one that most utilities have not thought about, but those few that have have found it very attractive. And it is available to all. The purpose of my testimony is to explain what it is, why it is financially attractive, and what some of the consequences for federal policy might be.

Over the past three years, a number of very thorough, detailed analyses have shown that specific utilities can meet all or nearly all of their own predicted growth needs, for the foreseeable future, without starting any large new central station power plants--if they invest their capital instead in a collection of alternative energy sources, including conservation in the form of increased end-use efficiency. And if they do make those alternative investments, the result will be the same energy yield, with at least the same reliability, in the same time frame, at lower cost both to the utility and to its ratepayers.

This, of course, is a very dramatic claim; and it suggests that utilities, in their concentration on nuclear and coal plants, have been ignoring a massive, cheap energy source. It is a claim I would not expect anyone to take on faith, least of all a responsible utility manager or government official. But what I can report to you is that the analyses that have shown this to be true, in several specific cases, have been attacked, cross-examined, run through with a fine-tooth comb, and challenged by the best experts utility money can buy--and they have proved to be sound. I have attached complete copies of four such studies to my testimony, all performed by the Environmental Defense Fund, covering specific utilities in the states of California, Arkansas, and Michigan. (As you can imagine, these studies have been extremely controversial, and they have come in for very strenuous attack in formal proceedings, focused particularly at the computer model which makes such analysis possible. I can't resist telling you that the computer consulting firm in Cambridge, Massachusetts that has been hired to fly around the country and testify against our computer model in different states has now decided to market a very similar model under its own name; and in its advertising it claims that the model makes it possible to analyze questions "central to policy-makers in a utility" and "invaluable to regulatory and advisory agencies. . .in assessing how alternative regulatory policies might affect the investments and performance of the utility industry.")

These analyses have had a very strong influence on utilities and on state energy policy in California, where the work has been focused, and they have been responsible for greatly increased utility interest in conservation investments, solar water heating investments, cogeneration, and the like. I expect that Commissioner Walker of the California Energy Commission will give you a more complete description later this morning. Most recently, one such analysis was responsible for causing Pacific Gas & Electric Company and Southern California Edison Company, two of the country's five largest utilities, to abandon their plans for the most expensive baseload coal plant ever proposed in the United States, the $4.8 billion, 2500 MW Allen-Warner Valley complex. (EDF's analysis of the alternatives to that project, showing the availability of over 20,000 GWH of alternative energy for those two utilities, all of which would be cheaper than developing a coal plant, is one of the four I have attached to my testimony; and its findings were reluctantly confirmed by the consultant that PG & E and Edison hired--and paid over $150,000--to refute it. Late last year, Southern California Edison announced a major shift of corporate policy, toward investment in the alternative energy sources I have been discussing, and said that by 1990 it expected that 30% of its anticipated 6000 MW of additional generation needs would be met by those alternative energy sources (see attached clippings). That announcement was described by the Washington Post, in a lead editorial, as "a little bit like Richard Nixon recognizing Red China," which perhaps overstates the case; but from a financial viewpoint, it was at least as overdue.

Similar changes are underway in other states, spurred in every case by a factual analysis of the financial benefits of investing in alternatives rather than in large central station plants. One conspicuous example is New England Electric System, whose chairman you will hear from later this morning. A major attraction of such investments is that each individual unit tends to be small, and relatively quickly completed, so that investments enter rate base with relatively short lag time. And the pace and direction of investments is extremely flexible, so that changes in need projections, either up or down, can be quickly accommodated. This is unlike the situation with large central station plants, where once you start, you're stuck--even if the demand growth you originally planned for starts to melt away on you during construction.

It is the essence of these studies that they are extremely specific, looking at real-world utilities with immediate real-world needs and real-world costs, and speaking the language of utility planners. It would be overreaching simply to extrapolate that the same results would obtain for every utility in every state. But there is one constant shown by the experience to date: every time you look seriously at the economic potential for these alternatives, you find much more than anyone expected, by orders of magnitude. This is an energy source lying under the very noses of utilities, made up of thoroughly unspeculative, known, tested energy sources, which is simply not being taken seriously because the necessary financial analysis has not been undertaken.

I should make one additional point about California. You may be assuming, as many experts do, that California's energy situation is very different from the situation in the Northeast, because California faces high growth and needs large amounts of new capacity, whereas the Northeast has too much capacity, and faces the different problem of lowering generation which is fired by oil. In fact, however, California is in very much the same position as I described for the Northeast. In the recent proceedings on the 2500 Allen-Warner Valley coal plant, California's two largest utilities took the position that the plant was not needed for growth (the official state growth forecast is below 1% per year), and that the reason it had to be built was to back out oil. (Southern California Edison in fact burns more oil than any other utility in the country.) The alternatives that were analyzed would, among other things, replace more oil more quickly than the utilities claimed was possible with the plant.

What does all this mean for federal energy policy? First, it suggests that at least a large part of the new energy that electric utilities need is already within their reach, in a form that can let them keep growing and yet help restore their financial health by greatly reducing the risk which is presently associated with plant investment. The obstacles to obtaining large enough amounts of this kind of energy have been greatly exaggerated; and the principal obstacle is simple lack of awareness, due to an embarrassing lack of analysis. Second, federal energy policy over the last several years, taken as a whole, has served primarily to distract attention from the most economically sound alternatives, by putting its primary stress (and primary dollar boost) on the massive central station option of nuclear power, and on massive centralized synthetic fuels technologies. To the extent it has supported smaller-scale, renewable sources like conservation and solar, it has emphasized advanced, high-technology forms of these sources, and has conveyed the impression that they are experimental, and manv years from full-scale commercial development by utilities. This too is a distraction. Even with renewable energy, DOE has succumbed to the high-technology fallacy, and encouraged utilities and the public to overlook the simpler, already developed technologies lying on the doorstep. Of course, this is not to say that everything DOE has funded is useless or misleading; for example, it has played an important role in advancing the development and testing of wind generators. But the key is implementation; and this DOE has neglected. For example, in hearings last year in California, Pacific Gas & Electric Company's own wind expert testified that the company could count on having several hundred MW of cost-effective and reliable wind machines in its supply plan, and could confidently plan today for them to be available starting in 1985, if it simply undertook an accelerated testing program on existing prototypes. But following DOE's footsteps, the company has proposed a slow testing program that, it claims, will not guarantee it a deployable wind machine that its planners can rely on in any significant amounts before 1990. And in the meantime, unnecessary new coal and nuclear plants continue to be proposed, despite their ever increasing financial risks. Federal policy choices for the electric utility industry have a tendency to enforce the same counter-productive stress on large central station plants, to the exclusion of alternatives. A particularly stark example is the proposal currently being floated by Secretary Edwards, that the Fuel Use Act be amended to focus on coal alone as the only fuel for oil backout, removing any requirement or incentive to consider alternatives, including the ones I have been discussing.

The experience I have been describing also suggests that a top priority for continued federal participation in electric energy policy should be to help utilities, and their regulators in the fifty states, to analyze the alternative energy sources available in clear financial terms, through objective, side-by-side cost comparisons, in individual cases and in full planning detail. As I have said before, the methodology to make these comparisons is available, relatively easy to use, and thoroughly tested by highly paid skeptics. DOE could play an enormously useful role in facilitating such analysis, providing technical support to regulatory bodies, and stressing the importance of looking at currently available energy options in financial terms, as utility investment options. In addition to its research role, it could take on a much more active demonstration and development role, acting among other things as a clearinghouse for information so that the wheel need not be perpetually reinvented by each utility who decides to take these options seriously--as is presently the case.

Some structural reforms of the utility industry that have been proposed, including relaxing the Utility Holding Company Act and allowing the creation of unregulated subsidiaries, are intended as ways to increase utility earnings without having to apply for rate relief in the traditional manner. The Environmental Defense Fund does not oppose such changes in principle, but we think it is important to stress that the real solution lies within existing institutions in their existing form, and that shuffling corporate boxes in search of tax or other advantages is one more distraction from the real solution: more money for the utilities, but spent not on more large central station plants, but on smaller-scale, renewable energy sources which are more profitable. If unregulated entities are better at developing these sources, then turn them loose. But if the entities are utility subsidiaries, then the question arises why these forms of energy should be treated any differently from traditional forms, particularly if they are just as reliable and more profitable--because to the extent they are, letting the utility pursue them through an unregulated subsidiary is simply keeping the financial benefit of lower-cost service away from ratepayers, and redistributing it to shareholders. (The assumption is that these energy sources are riskier than conventional plants, but the fact in many cases is the reverse. As a utility investment, conservation is much surer to work than coal or nuclear, and much surer to produce utility revenues on schedule.) On the other hand, if the entities in question are independent third parties, then the profit will go to them, and utility financial health will not improve. In any case, it seems to us that these issues are primarily for the individual states to resolve, and that, based on past experience, federal involvement in electric energy policy runs a high risk of enforcing conformity and stifling innovation and diversity, a risk which is perhaps greater than the risk of federal forbearance. We urge the subcommittee to think in terms of a maximum of information and analytic assistance, and a minimum of policy enforcement, as the ideal federal role.

WEDNESDAY, OCTOBER 29, 1980

The Washington Post

AN INDEPENDENT NEWSPAPER

The Future Is Now

THE CHAIRMAN of the state Public Utilities Commission termed it "a little like Richard Nixon's recognizing China." Environmentalists are calling it "a historic moment," and the head of the California Energy Commission says it is a "bold, clear move . . . [that] is going to shake up some stodgy utilities in other parts of the nation." "It" is the announcement of a dramatic shift in policy by Southern California Edison, one of the country's leading utilities.

Edison, which serves a growing part of the country, expects a 40 percent increase in demand for its electricity by 1990. To meet that need, it has two large nuclear projects nearing completion. Until two weeks ago, the utility had insisted that most of the remaining two-thirds of the necessary new capacity had to come from traditional energy sources, including two huge and controversial coal projects. Edison maintained that no more than 10 percent of its new supply could come from alternative energy sources, including conservation and renewable technologies.

In the course of routine licensing hearings for the new plants, the Environmental Defense Fund produced a detailed analysis showing, it said, that a combination of conservation and alternative sources could produce more energy at far less cost than the coal plants. A few months ago, an independent study by the Interior Department's Bureau of Land Management reached the same conclusion. Suddenly, about two weeks ago, Edison announced a major policy change "to make renewable our preferred technology—to make it happen."

According to Edison's new plan, nearly two million kilowatts, almost as much as is expected from the new nuclear plants, will be derived from wind, geothermal, solar, fuel cell and hydroelectric sources, and from cogeneration, one of the most promising conservation technologies. Planning for the new coal projects will continue, but Edison's own numbers indicate that the company expects eventually to drop one or both of them—assuming, of course, that the renewable resources perform as expected.

Edison attributed its change of mind to "some significant successes in a number of research and development areas." It seems equally likely that the utility also took a second look at such things as the skyrocketing costs of capital financing, the declining demand for electricity and the realistic technical potential of new energy sources. The hazards and delays of the regulatory process for large coal or nuclear plants, and the 10 years it now takes to build a new one (as compared with the two or three years required to build a smaller windmill or geothermal facility), must also have been powerful influences.

Regardless of the reasons for it, Edison's commitment is a courageous and welcome change of course. It should mean lower energy costs and less environmental damage for citizens of southern California. More important for the rest of the country, it may well have a greater impact on other utilities' thinking and planning than all the government and academic studies combined.

THE WALL STREET JOURNAL, Monday, October 20, 1980 5

S. California Edison Raises Commitment To Alternative Energy in 'Major Change'

By LAUREL LEFF

Staff Reporter of THE WALL STREET JOURNAL

LOS ANGELES—Southern California Edison Co. may have signaled a significant change in direction for public utilities and U.S. energy production.

After repeatedly saying that it didn't expect more than 10% of its energy to come from alternative sources, such as wind, solar and geothermal power by the end of this century, Edison announced Friday a "major change in corporate policy regarding the sources of future electricity for its customers." The utility said that by 1990, about 30%, or 1.9 million kilowatts of its anticipated six million kilowatts of additional generation needs, will be met by "renewable and alternate sources," including wind, goethermal and solar power, fuel cells, hydro-electricity, and cogeneration.

Daniel Yergin, an energy specialist at Harvard University's Kennedy School of Government, said Edison's program was a "bold, innovative and yet also reasonable way to proceed." Thomas Graff, regional counsel for the Environmental Defense Fund, which often has criticized Edison's energy policies, termed the occasion "an historic moment."

And John Bryson, president of the California Public Utilities Commission, noting the prior involvement of William Gould, Edison's chairman, with the San Onofre nuclear power plant, said, "It's a little like Richard Nixon recognizing China." Mr. Bryson also commented that Edison's announcement is "a nationally significant breakthrough in utility-resource planning" and that he "would expect to see other utilities follow Edison's lead."

Russell Schweickart, chairman of the California Energy Commission, said supply estimates represent "significant increases," from a June plan filed with the commission. Mr. Schweickart said estimates for supply from wind power has tripled, while solar has gone from "zero to 310 megawatts." Edison declined to specify how much additional spending it plans to develop these sources, saying that the budgets would be available by year end. Mr. Gould, the chairman, said the increase "will be significant." Larry Papay, vice president, resource development, said research and development funds for renewable and alternate energy will rise to $50 million in 1981, from $40 million this year.

Reaction from other utilities so far has been muted. Some utilities, particularly in the Northeast, say they will continue to depend heavily on more conventional energy sources such as nuclear power and coal. Mr. Bryson of the California Public Utility Commission predicted that the utilities' response may at first be "sharply critical" of Edison. "The utilities from an advocacy point of view have been working hard to convince the public that alternative energy isn't a viable approach," he said. With Edison's change in policy, the utilities "no longer present a united front," he added.

Many utilities have been exploring alternative energy sources, and some have limited projects in operation. But Edison is the first to announce that these fuels will constitute a major portion of its energy. "Our previous position was that we were going to rely on conservation and supplement that with renewable and alternate sources as they came along," explained Glenn Bjorklund, Edison's vice president, system development. "Our major policy change is to make renewable our preferred technology—to make it happen," he added.

Of its anticipated six million kilowatts of additional generation needs in 1990, Edison predicts that 2.3 million kilowatts will come from nuclear power, particularly two nuclear plants being constructed, and that 1.4 million kilowatts will come from out-of-state purchases. Edison expects 120,000 kilowatts from wind power, 420,000 kilowatts from geothermal power, 310,000 kilowatts from solar power, 130,000 kilowatts from fuel cells, 300,000 kilowatts from cogeneration and 620,000 kilowatts from hydroelectricity.

The biggest redirection of capital to alternative sources will be from Edison's "Cal Coal" and "Allen-Warner Valley" projects Mr. Bjorklund said Edison will continue "the permitting process" for the two planned coal plants, "but by the time the plants would be approved, in 1983 or 1984, we'll have a better handle on how much alternate power we'll have on line." Mr. Bjorklund said the company "won't go with both coal projects simultaneously."

Energy analysts disagree about what motivated Southern California Edison's change in direction. Mr. Gould attributed the policy shift to "some significant successes in a number of research and development areas." But none of the analysts interviewed noted any major technology breakthrough as the reason for Edison's abrupt change.

Some analysts claim California's tough regulatory requirements forced Edison to switch gears. "You look at conventional energy alternatives, at least in California, and there aren't any alternatives," said Ronald Watkins, vice president, resource planning, for San Diego Gas & Electric Co., another California utility. "The regulatory process effectively prohibits nuclear, it's extremely difficult to use coal, you can't count on using oil, you have to phase out natural gas, all that's left is alternative options," explained Richard Balzhiser, vice president, research, for the Palo Alto, Calif.-based Electric Power Research Institute.

But Mr. Bryson of the California Public Utility Commission said it isn't appropriate "to single out California" as particularly resistant to conventional energy sources. He said the cost of financing, the fluctuation in demand, and the long time required to build a plant have made nuclear power and coal much less attractive than they were 10 years ago. In contrast, the alternative energy sources usually consist of several different parts so the investment is spread around rather than concentrated in one huge unit. In addition, it takes two or three years for a windmill or geothermal station to begin service, the contrast to a nuclear power plant, which might take 10 years, Mr. Bryson said. Leonard Hyman, a vice president with Merrill Lynch Inc., agrees that when "you're dealing with smaller increments you can be more flexible." Mr. Hyman said that "more utility companies will be absolutely obliged to look at all these alternative sources."

When was the last time you heard from an enthusiastic utility executive? SoCal Ed's Bill Gould sees opportunity out there.

RECEIVED

"The prettiest hog at the fair"

By John Merwin

CHAIRMAN WILLIAM R. GOULD of Southern California Edison is an uncommonly philosophic man. "I always thought there were a number of great ages in which a man could have lived," he says. "It would be nice to have been the legate of a Roman legion in southern France when the empire was at peace. Or perhaps a big industrialist in Victorian England. And in the Fifties and Sixties, it would have been wonderful to be a utility executive.".

Gould's implication is clear: There are not-so-nice ages, too. For serfs, there were the Middle Ages; for Royalists, the English Civil War; and for utility executives, the Seventies. Plagued with angry bill-payers, regulators more interested in popularity than facts, costly environmental regulations, wild inflation, stock selling below book value, spiraling interest rates and high energy costs, being a utility executive in such querulous times is no fun.

But Gould, unlike so many utility executives today, is not complaining, at least not in public. A 61-year-old University of Utah graduate engineer who came to SoCal Ed 33 years ago fresh out of the Navy, Gould sees not decline and fall but challenge and growth. "I've read that the truly great opportunities come about when we are either building toward a new status quo, or tearing it down," he says. "Today what had been status quo is changing. There is opportunity. This is an exciting business."

What does this mean to $3.7 billion SoCal Ed, supplier of electricity to 3 million customers in vast areas of California outside the municipally supplied City of Los Angeles? Last fall, Gould announced that the company would take a radical new tack. Edison would attempt to develop one-third of its new power needs in this decade from alternate energy sources—from windmills, solar arrays and fuel cells—and not from the traditional oil-, gas- or coal-fired generating

Reflecting mirrors at Southern California Edison's Solar One facility in the Mojave Desert

While other utilities curse their fate, Edison tries to fill Eighties' power needs with wind, sun and geothermal steam.

FORBES, APRIL 27, 1981

plants that now supply 70% of the utility's 15,500-megawatt peak load capacity. It seems like a gamble, but to Gould it looks more like a reasonable plan.

"Some people will not hesitate to tell you that I'm out of my mind," Gould concedes. "But I think more will tell you that I'm credulous. Okay, but remember, if a species doesn't go through a mutation to meet its new environment, it doesn't survive. A corporation is in the same situation."

As with all electric utilities, SoCal Ed is facing a new set of rules: Growth in demand for electricity—that once doubled like clockwork every ten years—is no longer certain. Where bigness in generating plants used to mean economy, it now means expense. The whole technical picture is changing, but humans react slowly to change, which is where Gould's deft sense of internal politicking comes in.

Last fall Gould and Edison executives met for two days, charting the new course. Then, one day before the announcement, Gould sent a letter to employees, assuring them that the announced changes were more than window dressing. It would be necessary to change the way Edison did business, Gould wrote.

Gould also did some external politicking. He telephoned California's Governor Jerry Brown, Public Utilities Chairman John Bryson and neighboring utility executives to explain Edison's new direction. "I didn't want them to read about it first in the newspapers," Gould says. The next morning Edison held a big press conference and announced its corporate change, enthusiastically stressing a wholehearted commitment to alternate energy. PUC Chairman Bryson publicly praised Edison.

The strategy here is quite obvious: Since change is inevitable, Edison might as well relax and enjoy it.

Edison's willingness to innovate goes beyond the development of alternative energy sources. Last December, instead of sending the *de rigueur* lawyers to make its summary argument for the biennial rate case, Edison dispatched its president, Howard Allen. The day before, another utility's lawyer had been eaten alive by continual interruptions from skeptical commissioners. But a cool, thoroughly prepared Allen proceeded without interruption. Edison got 97% of the requested rate increase.

Even Claire Dedrick, a self-styled environmentalist whose PUC term recently expired, has praise for Edison's performance: "Allen was really effective. When you're getting answers from the president of the company, you know the company will back them. Edison also had the good sense to come in and tell us what was really bothering them. They didn't go through the usual rhetoric."

With Edison's current problems, it needs all the imagination and political skill it can muster. If sites are available, the cheapest power around is hydroelectric or the more commonly used coal. But hydroelectricity is hard to come by, and southern California's air quality nightmare makes coal-fired generators unwelcome. That forces Edison to burn oil and gas to generate two-thirds of its power, which is very bad news.

Edison's financial straits reflect the difficult circumstances. Last year SoCal Ed, after paying preferred dividends, earned $256.6 million, or $3.50 a share, but the quality of those earnings was horrendous. Of that bottom line, 63% wasn't real cash, but a utility accounting illusion called "allowance for funds used during construction," or AFDC. AFDC represents imaginary earnings from power plants under construction, as if those partially completed plants were actually operating and earning a cash return. Real cash earnings at Edison last year were $94.5 million, or $1.29 a share. Thus, to pay the $2.78 common dividend, Edison had to use borrowed money: Perhaps the most startling figure is this: Only 12% of Edison's 1980 capital expenditures of $728 million stemmed from cash flow—the other 88% had to be raised through stock sales or debt.

Edison's low-quality earnings result, in part, from the California regulatory process, which like that of 18 other states, doesn't allow return on uncompleted facilities. In Edison's case, $2.6 billion—one-third of its total invested capital—are in such construction projects, with $2 billion locked in the San Onofre nuclear project. The California PUC has decided that shareholders, not ratepayers, should bear the burden and risk of construction.

But California's regulatory environment is far from impossible. The PUC grants rate increases for coming years, instead of years past, which is critical when fuel prices are rising rapidly. In addition, California has taken the lead nationally in encouraging utilities to avoid building new plants, or to use someone else's money to do so. That means buying power from other utilities when possible, avoiding the drawn-out financial strain of building new power plants. It also means offering other private enterprises a chance to build and operate windmill parks, for instance, and sell the power to Edison. So some of California's utility policies—widely viewed as being antibusiness—work out to be in the interests of shareholders and investors.

"Without question we were once polarized," Gould says of Edison and the PUC. "We aren't now. We've both learned something. They are recognizing the need for conventional planning, while we are seeing that the world isn't what it once was."

In specific numbers, SoCal Ed's planners foresee a need for 6,000 megawatts of new capacity in the Eighties, one-third of that to retire oil-burning generators. (A megawatt is 1 million watts, enough electricity to serve 500 persons for a year.) They intend to acquire two-thirds of those 6,000 megawatts from nuclear facilities, such as the almost-completed 2,200-megawatt San Onofre nuclear station, which the utility has been building for nine years, and by purchasing power from other utilities. And for the crucial 2,000-megawatt final third, the company is betting that small-to-medium-size plants generating electricity from relatively untried technologies will do the job. Edison already has turbine windmills generating power from winds whistling through a pass near Palm Springs, and is building a pilot solar facility in the Mojave Desert. The company is also generating geothermal power in the Imperial Valley.

By using load management—persuading customers to spread power usage evenly during the day—Edison will reduce peak demand by 1,000 megawatts by 1990, enough to serve a city of 500,000. Last year alone Edison's conservation programs saved 5 million barrels of fuel oil. Meanwhile the company is concentrating on obtaining power from sources where construction can be easily delayed if electricity demand flags unexpectedly. While at the moment no utility stock is raising the investor's pulse, SoCal Ed's future seems promising. "We may be the prettiest hog at the fair," says Glenn Bjorklund, vice president in charge of systems development at SoCal Ed.

Not long ago Gould called together his executive team to decide whether to drop out of a proposed jointly owned, coal-fired plant slated for the late Eighties. The coal-fired plant would be a convenient backstop if Edison's alternative-energy plans aren't successful. Says Gould: "I asked our executives, 'Do you believe the new direction that we announced last fall? If you do, we can let this project go.' They did," he says, "and we cut loose the lifeboat."

The payoff? Gould reckons earnings would be about the same from a number of small plants or one big one. But the quality of earnings will be much better without all that cashless prosperity called "allowance for funds used during construction."

Meanwhile, Edison's near-term prospects aren't all that bad. Analysts predict that earnings this year should rebound to about $4.90. With the recently increased dividend, the stock, at a recent 24, yields better than 12%. If Gould is half right in his optimism, the Eighties could be as good for Edison as the Seventies were bad. ■

Mr. **Fuqua**. Thank you very much, Mr. Roe.

As I understand the statements of Mr. Benore and Mr. Ferrar, I think it was suggested by one of you that the Federal Energy Regulatory Commission should set a model for Federal regulation. On the other hand, I gathered at the close of your statement, Mr. Roe, that you think it is better the other way with the States setting the model. I see that as one fundamental difference that you might have from the other two witnesses.

I might ask—Mr. Benore, I forgot whether you or Mr. Ferrar made the comment.

Mr. **Benore**. I think we both may have made it.

Mr. **Fuqua**. Yes, I think so. I may be paraphrasing wrong.

Mr. **Benore**. Mr. Chairman, my observation would be that State regulation has not worked very well, and in testifying before at least half of these State regulatory commissions, I have developed from experience the observation that it is going to be very hard to get State regulatory commissions to fully recognize the problems of the electric power industry and to vigorously pursue a resolution of them.

I think that what we really need is some leadership. I think one of the best ways to make this possible is for the FERC to assume that role and to help show the State regulatory commissions by their actions, which would be very studied and carefully evaluated, what is necessary to provide a balance of equity for both the customer and the investor, and in so doing make electric service available on a reliable basis in the future.

In my judgment it is difficult to have confidence in something that hasn't worked or functioned very adequately based on empirical evidence. Constructive leadership will help.

Mr. **Roe**. Mr. Chairman, I think that is consistent with what I was suggesting. FERC is, after all, a regulatory commission with jurisdiction no individual State commission can handle.

Mr. **Fuqua**. Then FERC would have to be expanded.

Mr. **Roe**. I would assume in my remarks about State commissions FERC would be included, and I think the idea of FERC exercising a leadership role is an excellent idea. I have gone to FERC years ago and since, suggesting that part of their leadership be to take a more serious look at alternatives to large projects. I must say I have not gotten very far. That may be more my fault than FERC's.

I think the initiative the industry has in mind is in setting higher rates of return so they can go to the State commissions and say, "Look, FERC is giving us this rate of return on equity. Why don't you do the same?" That is also an important form of leadership and, as my testimony suggests we realize that is important.

But as far as FERC's role, I realize FERC's role would be strong and perhaps could be stronger. My comments would be directed more at DOE and DOE policy enforcement.

Mr. **Fuqua**. I have had utilities tell me, when I have talked to them about new technologies, "We are in such bad shape now that we can't sell any bonds if we go for a new technology, even say a fluidized bed for a coal-fired plant," which may be available before too long. I realize it is kind of a chicken-and-egg situation, but Mr.

Roe, you said on page 2 of your statement, and I want the other gentlemen to comment on it:

> If the utilities get the transfusion of money that they are asking for, but then use it to start another round of large central station power plants, they will very quickly be back, suffering again from the same financial anemia.

Mr. Ferrar, would you like to comment?

Mr. FERRAR. Yes, I'd be happy to. I think that is a non sequitur. It is not at all clear to me that additional money which would bring the rate of return up to the market rate of return that is equitable for other industries would necessarily trigger a new round of construction of central station projects. In fact, the essence of my remarks was to let life-cycle cost effectiveness be the principle of technology choice and not to restrict the utility industry or any other industry based on financial constraints that might lead to short-term decisionmaking that is not in the national interest.

So I think Mr. Roe is proposing we would immediately return to a new round of central station construction, and at this point I don't see that it would be the case.

Mr. FUQUA. If it were, do you think the utilities would suffer from the same financial anemia?

Mr. FERRAR. Pardon me?

Mr. FUQUA. If the utilities were to go to large central stations, do you think it would then add to their financial woes?

Mr. FERRAR. The financial woes are caused, in my opinion, primarily by the regulatory process. If it is the case that it can be absolutely shown to regulators and the public at large that central station technologies X, Y, or Z are indeed the cost-effective technologies that should be employed in service to the customers, I would hope we'd have a rational enough regulatory program that it would reward the investors for making that cost-conscious decision.

Mr. FUQUA. Thank you.

Mr. Weber.

Mr. WEBER. Thank you, Mr. Chairman.

Mr. Ferrar and Mr. Benore, you may want to respond to this. I think one of the central points in your testimony was that the growth rate in demand was less than before. You indicated in prior testimony that that was part of the problem the PUC's face. I'd like to try to address how much of the problem has been caused by reduction in demand.

The second part of my question would be: Can you give us some reasonable projection of what you are expecting for electrical demand in the near-term future?

Mr. FERRAR. I don't believe there is any question that the growth-rate in demand for electricity has moderated in the post-OPEC environment. The whole economy is going through a transition, and certainly this industry is going through that kind of transition as well. It is the case in this industry, because of the incredibly long leadtime for its projects, that there is a transitional factor we are experiencing. And I believe a lot of the discussion, both in the media and here in Congress and around the country in general, about the electric power industry is because of the transition, the stress, the inflexibility of this industry because of the long leadtime in terms of the kinds of projects that were underway at the time of the changed economic environment here.

Just as General Motors has had to move to the J car design, so does this industry have to move to a new posture or approach.

So, yes, I believe there has been a changing growth rate, and I believe the industry is consciously responding to that. But when there is a plant where a large amount of investment has been incurred and it's on its way to completion, prudent economic consideration requires bringing that plant to completion.

Mr. **Weber**. Is that the largest component of difficulty in the industry?

Mr. **Ferrar**. It is the fundamental problem in this whole industry.

Mr. **Weber**. Is there planning for a high demand growth?

Mr. **Ferrar**. I know of no company that is planning for a very high demand growth compared to the way they were before the OPEC situation occurred.

Mr. **Weber**. What kind of demand growth are you planning on?

Mr. **Ferrar**. We have done studies that indicate a range of 2 to 4 or 5 percent depending on the particular jurisdictions involved. Our study called, "Economic Growth in the Future," is a simulation of the American economy given expected growth rates in GNP. So it is not a forecast but it is saying, "If you want this growth rate in GNP and in real per capita income, then you would have to have this kind of electric demand growth."

Mr. **Weber**. Not being familiar with the study, I don't know what kind of assumptions you have made, but I guess I'd have to ask you to explain what kind of linkage you see there. It would seem to me one of the most important economic factors affecting the energy industry is the break in the linkage between GNP growth and energy consumption growth. And I presume that you accept that that direct line has been broken or altered in some degree, and I am wondering what assumptions the electric utility industry is making about the demand for electricity that is going to be required, given a certain growth in GNP.

Mr. **Ferrar**. I don't believe it has been broken. There is a relationship in the long run between GNP growth and the demand for energy and particularly electric power. There are a number of studies that have indicated electric power has a capacity to displace oil and gas in end use and the whole process can be modified in a way that permits it by using it to displace oil and gas.

So that linkage, I agree, is a subject of continued interrogation and certainly the post-OPEC environment has called that into severe question and we are looking at it.

I do not want to leave you with the impression that the experience of the last several years should be extrapolated ad infinitum into history. I believe when there is an immediate reaction to the new price of energy and price of electric power that you have to be careful you don't interpret the immediate events as being a harbinger of the future of this economy. That link is still there.

Mr. **Weber**. Mr. Roe, would you respond to that?

Mr. **Roe**. Congressman, growth is obviously one of the things everybody has to guess at, and I would dance around as much as Mr. Ferrar if you tried to pin me to a figure.

But the point that I think is important is that, all right, we have to make some guesses about growth. What I was talking about is independent of what the growth rate is. It is a question of which is the best way to fill your needs once you have guessed what your needs are going to be.

And the point that I made was that there is a very considerable virtue in small pieces when you are in a time of uncertainty, precisely because if predictions turn out to be wrong you can add more small pieces or not build as many small pieces and not have so much capital hung out to dry in a plant which depends on a continued sustained growth rate, which in the past decade has tended to melt away.

Mr. FUQUA. Mr. Dunn.

Mr. DUNN. Thank you, Mr. Chairman.

Mr. Benore, on the financial side you talked about the difficulties of attracting risk capital given the size of the ventures and the long term for realization of returns. But how, in exact technical language, do we say to stockholders, "Your return should be higher"? Are you suggesting a special issue of preferred stock or a higher yield rate on bonds? What technical financial tools are you suggesting they might use?

Mr. BENORE. With respect to the problems of capital availability, we need somehow to induce investors to want to invest their moneys and savings in electric utilities securities.

The way this can be done in the marketplace is either through a reduction of risk, an increase in return, or a combination of both, if both prove to be necessary.

In the immediate future, the most likely way of inducing more capital to be invested in this industry is to raise the returns to investors; that the return on the book common stock equity investment of investors in this industry is lower than the book or maturity returns on the U.S. Government's own bonds is an unfortunate and untenable position.

Mr. DUNN. Is that limited by law?

Mr. BENORE. I guess it is to some degree limited by law. Companies must go through the regulatory process to raise the return.

Mr. DUNN. There is no way Congress can say "you will automatically get a higher rate of return."

Mr. BENORE. I understand that, and that is one of the reasons I support making the FERC a model of equitable regulation. It is through that entity that I would hope there would be a way for Congress to influence State regulators so that (1) allowed returns would be at a fair level, and earned returns would also be at a fair level, (2) confiscation of investor ownership and return would cease, and (3) this industry could continue to function as a viable entity in the future.

Mr. DUNN. A question for Mr. Roe. How would you characterize the conservation programs—and I'm not talking about switching from coal to wind—but conservation programs such as the Government-sponsored weatherization program versus having the utilities do it, that is, offering a low interest rate to people who weatherize.

Mr. ROE. We have stressed the latter kind, company-sponsored, because it seems to us the company is in the best position to decide what is in its best economic interest. We are not talking about a utility investing because of social conscience, but because it's cheaper for it to get its energy that way than to build a chunk of a plant. And the utility faces very different economics from the homeowner in that situation. If you are a homeowner you can insulate your attic, but you can't keep the utility from building the little pieces of the plant that that will save.

If you are the utility and you put insulation in your attic, you can count on that saving. So your economics are very different and encourage you to invest a good deal more money in these kinds of things.

The other problem with the Federal program is that it can't be tied to the specifics of a given utility, a given service area, so that inevitably there are going to be uneconomic choices forced on investors.

Mr. DUNN. I would agree but they would be better able to delineate at the local level which homes or which offices may need that service than a Federal bureaucrat in Washington.

Mr. ROE. Obviously a New Jersey utility and a Florida utility face a very different service characteristic in terms of whether you could get conservation. Weather stripping might make a lot of sense in one place but not in the other.

I might also point out we have looked very thoroughly at not just low-interest programs but utilities bearing a hundred percent of cost, only up to the point where it is cheaper for them to do that than to invest in whatever the marginal supply option is.

Mr. DUNN. Given the cost in the majority of cases today, it's cheaper?

Mr. ROE. I believe that is correct. It certainly has been in every case that we have looked at thoroughly.

Mr. DUNN. Thank you, Mr. Chairman.

Mr. FUQUA. Mr. Gregg.

Mr. GREGG. Thank you, Mr. Chairman.

Mr. Ferrar, I would refer you to the report that just came out from the New England Congressional Caucus which indicates there has been a 6-percent drop in the use of energy, whereas there has been a 4-percent increase in the gross production of goods and services in New England. This flies in the face of the statement that you cannot increase your economy while cutting energy costs. Obviously, there were more savings in the short term, and we expect the energy decline to stabilize or zero out. But we don't expect energy demand to increase at anywhere near the rate of economic growth.

So I think we are setting a pattern in New England that goes to Mr. Weber's point that we shouldn't always link GNP and energy growth. This leads me to my main issue of concern, which is how to raise capital for an industry which is confronting a flattening out of its growth rate in many parts of the country and is highly regulated at the same time. And your suggestion is that we raise the rate of return on investment in that sort of industry.

How do you ever make an industry which is in that sort of a crunch attractive to an investor when they can choose much safer stock that is going to have a chance of greater increase?

Mr. **Benore**. I think it is important to make it attractive to investors because it is an industry which provides an indispensable service upon which our economy and, growth so vitally depend.

Slow growth and an imbalance between revenue and cost growth can be overcome with additional rate relief.

It would mean that customer rates would rise more rapidly than they otherwise would—that certainly is true. But it is, necessary to add enough revenues so that the costs will be covered and so that there will be a fair return to investors.

Mr. **Gregg**. Well, what do you perceive as an adequate return to investors?

Mr. **Benore**. I believe on the common equity capital of the typical electric power company, unlike the 11 percent that is now being earned on their capital, and compared to 16 percent on money market funds, a prime rate of 20 percent, and 15 to 17 percent on the bonds of electric power companies that the minimum cost of common equity capital is 18 percent. This is the return which electric power companies on average must earn on their common stock investment.

Mr. **Gregg**. If you are going to realize an 18-percent return and are going to pass that on to the ratepayers, won't you put yourself in a position where it will be impossible for an average public utility commission to set that kind of rate?

Mr. **Benore**. I realize at first blush that it would seem to be politically unpalatable. The leverage in the income statement of electric companies is such (because net income for common stock is a small percentage of operating revenues) that an additional 12½-percent rate increase could increase the return from where it is now to about 18 percent on common stock invested capital. So the incremental amount of rate relief, because of the leverage in the income account, is not that great. It is not nearly as great as one would perceive it to be.

Second, I ask one to consider what are the consequences if we don't pay a fair price for the cost of electric power service.

I, for one, am not willing to walk many miles to try to get to work or to go without hot water or to not have employment or not have growth in our economy. Some things are very indispensable, and I believe electricity is one such thing. And I believe the economic costs of not having it far outweigh the incremental costs of providing to the investor, who made this service possible, a fair return. The investor isn't asking for an excessive return. He or she is only asking for a fair return. And for the last decade, the investor has been subsidizing the cost of electric power service.

This is an untenable position, an unreasonable position, an unfair position, and a position that can go on forever.

Mr. **Gregg**. I yield to the gentleman from Minnesota.

Mr. **Weber**. I don't disagree with that at all, but given the sensitivity to price that energy demand has shown lately, aren't we going to get into a vicious circle? Won't those increases have an effect on demand which will promote greater rate increases, which will again affect demand?

Mr. **Benore**. I have compared and checked these numbers and am almost a little suspect of them because my impression that electricity prices have been growing very, very dramatically, and that the portion of the budget or household income that electricity consumes has been rising at a very dramatic rate.

But I took the typical electric bill that the Edison Electric Institute provides annually and adjusted it for inflation and compared it to the median household income that I found in the Economic Report of the President to Congress in 1981.

I further adjusted the typical electric bill for the change in usage. One of the reasons, of course, that the electric bill rises is that we have been using more and more electricity.

I found that in 1970, based on constant usage and adjusted for inflation that the electric bill was 1.91 percent of the median household income. It rose to 2.17 percent in 1975. And to my surprise it then declined to an estimated 2.05 percent in 1980.

The electric bill is rising to a large degree because of inflation. At 15-percent inflation, everything triples in 8 years, just to give you some idea of what inflation is doing to the cost of everything.

When you adjust for inflation and usage, the electric bill really hasn't been increasing very dramatically at all. When I look at these numbers, I think that the electric power industry deserves a lot of credit for keeping electric bills relative to income as low as they are, and one should recognize that they have been kept so low, in part through investor subsidation.

I don't think price elasticity is as serious a problem as we sense it is.

Mr. FUQUA. Thank you.

Mr. WOLPE. Thank you, Mr. Chairman.

Just to sharpen the focus for a moment, it seems to me there is no quarrel with the problems facing the utilities. I don't think that is the issue, and I don't think that is in dispute among the various viewpoints that have been expressed or among those who have asked the questions.

The issue is, first: How did utilities get into that situation? And, second, how can we most quickly and easily get out of that situation in the future?

I am a little confused for the moment, Mr. Ferrar, by the thrust of your testimony. What I heard you say at one point was that you would identify as primarily responsible for the financial problems facing the utilities the fact that utilities were not seeing a reasonable rate of return.

But at another point, under questioning of I believe Mr. Weber, I think you acknowledged that one of the real problems—"fundamental" was the term you used—was the overexpectation of the utilities with respect to growth projections. That is, demand for electricity simply did not grow as fast as utilities had anticipated in their powerplant plans and implementing those plans.

Did I hear you right? Were you canceling out your first point by the second?

Mr. FERRAR. No; I believe the problem is a regulatory problem. In my discussion about growth rate, I was acknowledging the fact that growth rates have moderated, and when that happens in a long-leadtime industry there is an adjustment necessary. There has to be a changed planning environment.

Mr. Wolpe. You are aware, are you not, that the utility industry has consistently had high growth rate projection in comparison with independent analyses performed by State regulatory bodies?

Mr. Ferrar. They have had higher expectations, that is right. They have had the job to serve customers. It is their job to do so.

Mr. Wolpe. Why are you so confident it is the regulatory climate rather than industry miscalculations that is responsible?

Mr. Ferrar. Let me finish my previous answer. Yes, the forecasts were high compared to some other forecasts. I agree with that. I think if you look at other industries, particularly large capital-intensive industries, whether it is automobile or airline or what have you, they did not anticipate the OPEC environment. Yes, I think the whole environment suffers from that forecasting problem because forecasting, when you change the fundamental characteristic of the economy, becomes very difficult to do.

Mr. Wolpe. But other industries that have miscalculated in their projections have had to essentially eat the cost of their miscalculations, have they not?

Mr. Ferrar. Yes, and from a profit margin that they could do so. It is the case in the economy that normal private-sector investors are earning a risk premium to accommodate and cushion these facts. The fact is that this industry, as Mr. Benore pointed out, has not had a risk premium for 15 years that its investors were enjoying. And, therefore, to lean on them and ask them to accommodate this kind of transition creates an impossible chore.

Mr. Wolpe. The utilities had a 15- to 20-percent reserve capacity required to do the job; is that correct?

Mr. Ferrar. The standard varies, but yes, there is a reserve margin in the order of 15 to 20 percent nationally, right.

Mr. Wolpe. It is my understanding also that on a national basis—there are regional exceptions—the reserve capacity is closer to 40 percent.

Mr. Ferrar. On the national basis—there are regional shortfalls, but on a national basis reserves are higher than planned.

I would like to point out that in my opinion reserve margins should be a lower bound, to maintain service adequate to reliably service customers. However, it can be shown higher reserve margins can be absolutely compatible with lower prices to customers, especially in times when you have to get off oil. In this economy, where the price of oil has risen above expectations, some plants are obsolete. There remains a higher reserve margin, granted, but from the standpoint of economics and welfare of customers, I am not sure of its relevance.

Mr. Wolpe. That is interesting. Then if that is the case, why do we establish the 15- to 20-percent benchmark? Are you saying we should really have a 40-percent one?

Mr. Ferrar. No, I'm saying 15 to 20 percent has reason to be the minimum reserve requirement to assure reliable service. However, if it is dictated that a higher reserve margin is in the customer's interest for supplying him cheaper service, then we should not use that 15- to 20-percent margin as an upper bound but only as a lower bound.

Mr. Wolpe. Thank you, Mr. Chairman.

Mr. Fuqua. Let me remind members that we have an equally good and stimulating panel following these gentlemen, and while it is very interesting and the questions are very good, we are in somewhat of a time crunch.

Mr. McGrath.

Mr. McGrath. I will be very helpful, Mr. Chairman.

Mr. Fuqua. Thank you.

Mr. McGrath. I have only one question.

The development of new energy systems includes basic research and demonstration. In light of the financial situation that utilities find themselves in today, how reasonable is it for us to expect an equal participation from the utilities in these demonstration projects?

Mr. Ferrar. My remarks suggested that a financially healthy industry would make reasonable investments in research and development. This is true with all of the industries in this economy, of course. This electric power industry, of course, does have a research institute which is cost sharing on development.

As you look across the spectrum of research and development. you go from basic research, which is really futuristic kinds of investigations——

Mr. McGrath. I believe that basic research clearly has a role.

Mr. Ferrar. Fine.

Mr. McGrath. What is unclear, then, would be the demonstration. What I am trying to elicit from you is your thoughts as to how much those people who are going to benefit perhaps by the commercialization of the system—how much they should contribute toward the demonstration.

Mr. Ferrar. I think if the industry was financially healthy, that is, if market-to-book ratios of utility common stock were at least 1.0 as is reasonable to expect in other industries—in fact, in all other industries it's around 1.43—if you have a financially healthy industry that is not timid of taking on risks, then I believe the industry can take on the lion's share of that burden, especially in the conditions we find ourselves in this economy right now.

Mr. McGrath. I have no further questions.

Mr. Fuqua. Thank you very much, Mr. McGrath.

Mr. Walker.

Mr. Walker. Thank you, Mr. Chairman.

Mr. Benore, what would a bankruptcy of General Public Utilities mean to investors and ultimately to rates across the country?

Mr. Benore. I believe a bankruptcy of General Public Utilities would remind individual investors, who have almost a blind faith in the viability of the electric power industry, that financial viability is no longer assured. Their faith was already shaken when Consolidated Edison Co. omitted its dividend in 1974. We saw the response to that. The average price for the typical electric power company that year dropped by a third, and some by a half.

I don't think the price reduction would be that substantial, in part because it is not coming as a complete surprise. There are plenty of periodical and newspaper articles that are alerting people to this possibility.

Second, it shouldn't affect all electric power companies because it is nuclear power related.

Nonetheless, I believe it would jar the faith of buyers of the securities of this industry. As to how badly it would jar them and what effect it would have on capital availability I can't be sure, except to say that capital availability would be substantially reduced.

Furthermore, because the investor would perceive even more risk than she or he now senses, the cost of capital would rise. Again I can't tell you how much that would be, but it would rise.

It would, in summary, have a very adverse impact on capital costs and capital availability, and I think especially on the ability of other electric power companies building nuclear powerplants to attract the capital that they need to complete them.

Mr. **Walker**. Mr. Roe, you talked in terms of a conservation program and the advantages of moving in that direction—smaller investment, smaller capital cost.

It seems to me a lot of the conservation materials that I have seen put a great deal of emphasis on cogeneration of one kind or another on district heating programs. This committee was recently in Finland where we had a chance to talk to Finnish officials who have gone heavily toward district heating. We found out from them there is a substantial capital investment involved in those kinds of programs as well.

Could you explain why there would be an advantage in making that kind of massive capital investment over putting it in a new plant and production facilities?

Mr. **Roe**. All the things I have been talking about do require very substantial amounts of capital. I am not talking about any free rides.

All I have been talking about is that when you do a serious economic comparison of which is the better investment, these turn out to be better—not free, simply less expensive in the long run.

And the reason is not that they are small. You may be talking about a need of 10,000 megawatts. It is that they come in small pieces. And because of the reasons Mr. Benore described in his testimony, there are very important advantages under regulation to investing in small pieces that enter the rate base 6, 8, 10, 12 months after you begin the investment, rather than having the investment stay out there for 10 years building up.

So it is not that they are in small amounts but that they come in small pieces, 10,000 one-megawatt chunks rather than one 10,000-megawatt chunk. And the way the utilities are regulated and get their money, that is much more attractive to them, even if the total dollar cost is the same, to get their money more quickly in the rate base.

I think this goes to what Mr. Wolpe was talking about in terms of how do you make the utilities more attractive to investors. One way is obviously to have them start conducting business in a way that is going to cut down on their financial risk and is going to secure them higher rates of return.

My own guess, for what it's worth, is that in the 50 States where utilities have to convince regulators to increase rates of return, one thing that will make them convincing is a posture of, "We are changing the way we are doing business. We are adapting to the modern world. We are thinking about sinking serious amounts of money into an array of alternatives that are secure, domestic, and have very short payout."

Mr. **Walker**. Mr. Ferrar, how do the utilities go about looking toward the future in terms of capacity needs? I spent a good deal of time looking at the future of the automobile industry. One of the things that we seem to be moving toward there is the advent of electric cars. It seems to me if they went to many substantial numbers of them it would cause a substantial drain on utility capacity.

What kind of planning is being done at this point for that sort of adding of perhaps a much larger demand?

Mr. **Ferrar**. That is a much larger point, Mr. Walker. It is important in a long-lead-time industry, such as we have, to plan in general, because the world changes so rapidly over a 30-year period, but particularly we have an obligation to serve customers. That is our obligation, and therefore there is a need to plan for these new technologies which we may find are going into the system, not only the electric car but a lot of other advances. The electric power industry has to be there and have the capacity ready to go in order to supply that energy.

So it does create a certain uncertainty in the planning process that has to be accommodated for in our planning.

There is no quick answer to your question. You use econometric analysis and then recognize the limitations of that and apply reasoned judgment.

Mr. **Walker**. Thank you.

Mr. **Fuqua**. Thank you, Mr. Walker.

Mr. Ertel.

Mr. **Ertel**. Thank you, Mr. Chairman.

Mr. Benore, Mr. Walker asked you about the potential bankruptcy of GPU. Are you aware of the study by Rothschild of the effects on GPU because of the Three Mile Island accident?

Mr. **Benore**. I am not intimately familiar with it. I have seen it and scanned it, but I have not studied it.

Mr. **Ertel**. I think his conclusion is that, frankly, we are paying and will pay in the future for that through out the utility industry. And the reason we are paying is because the risk perception has gone up. He has gone back and used Con Ed and other things that have happened to indicate there are certainly subjective judgments in the analysis as well. And he has also indicated that the high cost of capital to utilities reflects the incident at Three Mile Island and will continue to do so if there is a bankruptcy.

But he goes one step further. You limited your testimony to saying it would probably cause difficulty for those who have nuclear plants. He goes farther and says it would apply across the entire field, although probably not as dramatically as it would just to nuclear. He makes that judgment on the basis that people probably won't differentiate that much between nuclear and nonnuclear utilities. They just look at the risk of the enterprise, and the regulatory climate, which indicates that one of the reasons GPU may have gone bankrupt is because of the regulators.

So, therefore, you can apply that reasoning, I suppose—he hasn't spelled that out—to the entire utility field.

Would you differ with that judgment?

Mr. **Benore**. I don't differ with one of the assumptions underlying that judgment that I heard you mention, and that is that investors may not discriminate according to the fuel generation sources of electric power companies.

Such an investor, however, would not be a sophisticated or knowledgeable investor because fuel mix surveys and studies are published by my firm and many others, and widely available to investors. To the extent that there was no discrimination, I can easily understand how other electric power companies would be affected.

I am not doing my job as an investment advisor, and perhaps others are not as well, unless we help those investors to discriminate. And I would hope that we could do our job in keeping the markets as efficiently postured as we can. Perfect efficiency is, of course, impossible.

Mr. **Ertel**. I can understand your position. Quite frankly, if I were in your role I would want to make the distinction between coal-powered, oil, gas, whatever.

But the point is, that is one prong of the argument. The other prong I never heard him discuss, at least in the paper I have seen, is the fact that you've got a regulatory climate which would in fact push GPU to the wall. Essentially if they could recover their costs they could clean up Three Mile Island. But if it becomes a perception that the regulatory climate is so bad for the utilities, won't that in fact raise the risk premium across the entire utility industry even outside nuclear?

Mr. **Benore**. Yes; I think that is a valid argument. I believe the regulatory environment in Pennsylvania would be regarded as one that was forcing investors to accept all the risks, and that could be applied to all situations or all risks incurred by utilities operating in that State.

So I think there is a basis for feeling that within that State and even beyond where regulation is thought to be consumer oriented that the cost of capital to other companies would increase and that capital availability to those companies would probably decline.

Mr. **Ertel**. Now, if that is a true analysis, then why in your judgment has not the electric utility industry been interested in depth—there has been some surface movement—in trying to resolve the problems of that one utility which is the sore thumb, if you will, of all the utilities at this point?

I'd like to hear from Mr. Ferrar on that, even though I note from his background here he's got some connection with GPU. So I suspect that may have some influence on his judgment.

Mr. **Benore**. I cannot speak for the industry. I am not that familiar with their attitudes or their endeavors in trying to help general public utilities. I can reason why there might be a couple of problems. One of these is that some companies such as Hawaiian Electric, for example, on another shore, may feel that it is not part of the problem. It doesn't have a nuclear involvement at all.

Another problem that might prevail is—-

Mr. **Ertel**. Let me interrupt you. I know my time is up. But if they perceive their costs are going to go up as a result of the actions there, why shouldn't they be concerned?

Mr. **Benore**. Their costs should not go up if the market operates efficiently in the sense this is a nuclear-derived problem, but I agree that the market is not perfectly efficient.

The other problem is that the electric power industry doesn't have a lot of money. With its languishing financial shape, it doesn't have a lot of money to contribute. And in the sense that it doesn't have the money and perhaps there is some concern that regulators would not allow them to recover such money, maybe they just can't afford it.

Mr. **Ertel**. I thank the chairman for his indulgence. I must point out you just made the best argument for the bill I have introduced, which would require the nuclear utility industry to try to assist anybody who is hurt.

Thanks for the help. You didn't know you did it.

Mr. **Fuqua**. Thank you.

Mr. Sensenbrenner.

Mr. **Sensenbrenner**. No questions.

Mr. **Fuqua**. Thank you very much.

I want to thank our panel. I think you can tell from the time we have consumed it has been a very stimulating and interesting discussion this morning. I want to thank you all for your contribution.

Our next panel will be Mr. Charles Curtis, attorney at law in Washington with Van Ness, Feldman & Sutcliffe; Mr. Jim Walker, commissioner of the California Energy Commission; and Mr. Robert Hemphill, Director of the Division of Energy Conservation and Rates of the Tennessee Valley Authority.

I apologize, Mr. Curtis. I would point out to the committee that in addition to the three names I listed, the et als. include Curtis and Levenberg.

Mr. Curtis, we want to thank you for coming and giving us the benefit of your views on this matter.

STATEMENT OF CHARLES CURTIS, VAN NESS, FELDMAN, SUTCLIFFE, CURTIS & LEVENBERG, WASHINGTON, D.C.; JIM WALKER, COMMISSIONER, CALIFORNIA ENERGY COMMISSION, SACRAMENTO, CALIF.; AND ROBERT HEMPHILL, DIRECTOR, DIVISION OF ENERGY CONSERVATION AND RATES, TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TENN.

Mr. **Curtis**. Thank you, Mr. Chairman. I, too, will attempt to summarize my remarks.

Mr. **Fuqua**. Thank you. We will make your statement in its entirety a part of the record.

Mr. **Curtis**. Thank you, sir.

First, I am pleased to appear in response to your invitation to testify and to express some views on "The Future of the Nation's Energy Utilities," and particularly the electric utility industry.

I would like to call the attention of the members of the committee to a footnote on the first page of my statement so that the committee is fully aware that the clients of the firm of which I am a member do have an interest in this proceeding, although I have steadfastly attempted to give to the committee my untempered and unqualified views on this matter.

The proposals for regulatory and institutional change have, I believe, a common ground that you heard expressed by the first panel, namely, a growing realization that the regulatory process has not worked well in dealing with the dynamics of today's markets.

The essential problem, at least as I understand it, appears to be that the electric utility industry, buffeted by sharp increases in fuel and inflation-bloated construction costs and caught under a time-consuming adjudicatory process pursuant to which it must apply to increase its rates, has become quite risky. And neither the allowed nor the earned rates of return adequately compensate investors for that risk taking. Consequently, several proposals have surfaced which suggest:

1. Increasing the allowed rates of return to levels appropriate to the risk incidence and sufficient to restore the economic vitality of the industry. This is the risk compensation option.
2. Reducing the risk through various reforms in the regulatory process to allow for more timely rate increases, automatic cost adjustments, recovery in rate base of construction work in progress and the like. This is what I would call the risk reduction or risk-shifting option.
3. Turning to investment in nonregulated activities to improve overall performance and diversify risk. This I would call the diversification option. And although, as Mr. Ferrar noted in his remarks this morning, it is not a panacea, it has proved very effective in improving the financial circumstances of several regulated utilities. But it is not an option generally available to all participants in the electric utility sector.
4. The fourth option is removing utility-type regulatory controls on power production, or the decontrol option.

To some extent the implementation of each of these options will require favorable action at both the Federal and State level. The electric utility industry is today subject to a system of plenary regulation. It will take a great deal of effort and time to alter the existing structure in any significant way. So nothing is about to happen overnight.

I would be happy to comment on each of these options in my oral presentation or in response to questions which the subcommittee may wish to direct to me. But I would like to confine my written statement to the last of these—the decontrol option. This is easily the option attracting the most discussion and interest today.

Before beginning a discussion of the deregulation option, however, I should disclose a considerable bias. One might think that the decontrol option is an outgrowth of the current trend to critically appraise all forms of economic regulation, such as the national efforts to deregulate trucking, airlines, railroads, and the like. But in my view, it is not a mere extension of those initiatives. True, it has something to do with the recognition that the present form of regulation is inadequately coping with current circumstances.

I suspect, however, that the primary reason that we are today speaking of a decontrol option for electric utilities has a lot more to do with the serious financial condition of this industry and the perception of some that the decontrol option may give the industry an opportunity to improve on its financial circumstances to an extent that the political or practical constraints of the regulatory process will not allow. To those who believe that decontrol offers a cure to the industry's financial woes, I must say I respectfully but earnestly disagree.

The deregulation option presents serious questions warranting serious study and evaluation. But it must be recognized that its salutary effects or benefits, if realized, will be achieved over the very long term. The financial crisis confronted by the industry is substantial and immediate. I believe we should instead concentrate our primary focus and energies on reforming the rate regulatory process, to improve its efficiency, to improve its predictability, and to find some means for accommodating to the dynamics of the marketplace. Such a task will be itself a considerable undertaking; some of its accomplishments may be some time off. But, generally speaking, this course offers a better opportunity for getting relief in the near term, at least for some of the most financially distressed, and greater certainty in result.

As I understand it, the question which the subcommittee seeks to answer is: What effect would the decontrol of electric power generation have on the introduction of new technologies? As you might expect, the answer I will give is that "It depends."

Today nonutility-owned small power production and cogeneration facilities qualifying under the Public Utility Regulatory Policies Act, or PURPA, are exempt from State and Federal rate regulation and the constraints of the Public Utility Holding Company Act. Moreover, a qualifying facility may require the electric utility in its service area to purchase the power produced and to do so at a price equal to the system's avoided cost.

This latter facet of the PURPA program provides strong incentives to the development of these diversified power sources. As a consequence, substantial entrepreneurial initiatives and investments are beginning to take hold in small hydro development, biomass conversion—particularly refuse-to-energy projects—wind, cogeneration, and other qualifying applications.

There is today a strong market for new technologies in these areas, although there are some constraints on scale efficiencies. In the case of cogeneration, there is no size limit, but qualifying small power-production facilities may not be greater than 80 megawatts and in some instances the benefits of the program are limited to facilities of 30 megawatts.

Would the decontrol option contemplate removing the regulatory aspects of the PURPA program? In other words, in a decontrolled market, could qualifying facilities continue to insist on a compelled purchase of output at a price determined in relationship to the utility's avoided cost? If not, the decontrol option may result in a diminished market for decentralized applications.

On the other hand, size limitations would be removed, as would the limitations on utility ownership participation. This could expand the market for decentralized technologies, particularly if electric utilities were permitted to price output of new facilities at the system's avoided cost—calculated, of course, without regard to the capacity to be added—and regulatory commissions determined other regulated rates for transmission and distribution without regard to the earnings from additions to generation. But those are big "ifs," and we would have to see.

I find it difficult to understand who it is, other than electric utilities, that will enter the market to build central station facilities under a deregulation scenario. Such projects involve high front-end capital costs and long leadtimes. Typically they involve compliance with a broad range of land use, safety, and environmental controls which, however sensible or necessary, add to risks during construction and raise problems with cost containment. Presumably these facilities would have to be project financed and will require payouts in less than the 20- to 30-year period typical for utility property. Both the project financing and the shorter payout period will add to the costs.

Undoubtedly, the capital markets will demand that the power producer demonstrate a market for its output in the form of a long-term purchase power contract. And, as likely, the purchasing distribution system will require regulatory approval in advance to be assured that it will be able to passthrough the purchased power costs. Here lies the problem.

Indirect regulation at the distribution level is likely to balk at the pricing terms necessary to attract capital to these investments. Unregulated power producers are not apt to agree to fixed-price terms, and regulatory commissions, which have been reluctant to approve indexing of prices and construction work in progress for electric utilities, would not be expected to approve their equivalent in contractual terms as a part of the purchase power agreement. Without the equivalent of cost-plus terms the project is unlikely to be financed. With them, what has the consumer gained?

Indeed, it would seem to be the usual case that non-utility project financing of central station generation will prove to be more costly than if the utility built the facility itself. Moreover, I have some concern that the necessity to resort to project financing by non-utilities would tend to limit the introduction of new technologies inasmuch as the private power producer would have to accept most of the front-end risks of technological failure. Today's regulatory system would seem to provide more avenues for distributing those risks over the total system or sharing those risks with ratepayers. It is not apparent that the purchase power contract in a deregulated market which relies on project financing would provide comparable opportunities.

If the electric utility itself were to build central station facilities in a deregulated market, it would encounter similar, although perhaps more difficult, problems. If the facility construction is to be financed through a separate entity, like the non-utility entrepreneur, project financing probably will be required. But here, because the purchase power contract is a matter of dealing between affiliates, the regulatory commissions are likely to be even stricter in reviewing the terms of the buyer's purchase decision. Moreover, they are not likely to approve price terms which appear to result in substantially higher returns on investment than the utility would have been allowed under a cost-based regulatory system. Some might, however.

Accordingly, the deregulation option may provide an opportunity—and the necessary political shelter—for an otherwise willing

State regulatory commission to allow something more than cost-based rates for investment in addition to capacity. If this occurs with some frequency, the deregulation option may have more significant effects than are now apparent to me. Consequently, it is difficult to predict precisely what effect the deregulation option may have on future investment by utilities in central station power sources. But here, too, it would seem that the resort to project financing would have a tendency to discourage the introduction of new technologies.

Whether the deregulation option will provide significant benefits to the Nation or the electric utility industry and its customers, I really do not know. Right now I see mostly problems. That merely reflects my abounding skepticism of simple solutions.

Mr. Chairman, I thank you for the opportunity to appear before you, and of course I will be happy to respond to questions.

[The prepared statement of Mr. Curtis follows:]

REMARKS OF
CHARLES B. CURTIS
VAN NESS, FELDMAN, SUTCLIFFE, CURTIS & LEVENBERG

Before the

COMMITTEE ON SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES
Washington, D. C. 20515

SUBCOMMITTEE ON ENERGY DEVELOPMENT & APPLICATIONS

Hearing on

THE FUTURE OF THE NATION'S ENERGY UTILITIES

June 23, 1981

Mr. Chairman, members of the subcommittee, I am pleased to appear in response to your invitation to testify on "The Future of the Nation's Energy Utilities." Your letter indicated that you wished to focus primarily on the electric utility industry. So I will confine my remarks to that sector. 1/

There is today a growing realization that electric utilities are facing a sustained and serious financial crisis. Claims of economic distress in the past, overstated and colored by the passion of advocacy, have largely been discounted or disregarded. But now, the wolf is at the door and can be ignored only at considerable peril. One must take seriously the financial plight of an industry which commands such a significant portion of this nation's capital investment and upon which our economy so much depends.

1/ At the outset I want to note for the record that, while I have attempted to provide the subcommittee with my own views untempered or unshaped by client considerations, the subcommittee should be aware that the law firm of which I am a member represents electric utilities and others who have some interest in the subject matter of these proceedings.

I know this subcommittee takes this matter seriously. Under your direction, substantial amounts have been invested in the development of technologies to improve on and diversifying the production of electric energy. It is reasonable to ask whether the current state of affairs allows for market acceptance and commercial application of these technologies.

In this respect, your inquiry is not unlike that of a Westinghouse or other purveyor of production related technologies -- is the market for the fruits of the RD&D investment sufficient to justify the expenditure of funds and are structural changes likely to occur in the marketplace that provide guidance in determining how (in which technologies) those funds should be invested? I am not sure my remarks will provide a very explicit answer to this question. But I hope they will assist you in understanding some of the various proposals for institutional and regulatory reform that are being discussed within the industry, in some governmental circles, and by concerned outsiders.

The proposals for regulatory and institutional change have, I believe, a common ground -- a growing realization that the regulatory process has not worked well in dealing with the dynamics of today's markets. Soaring construction and capital costs have not been matched by commensurate increases in revenues. Institutional investors have largely abandoned the industry and the small investor's judgment of investment value is reflected in low price-to-book ratios which demonstrate that the returns earned by utilities are not adequate. There exists substantial question whether electric utilities will be able to raise the projected $300 to $500 billion estimated to be required between now and 1990. I expect that Charles Benore's remarks on the previous panel demonstrated this concern in bright detail.

The problem - at least as I understand it - appears to be that the electric utility industry, buffeted by sharp increases in fuel and inflation bloated construction costs and caught under a time consuming adjudicatory process pursuant to which it must apply to increase its rates, has become quite risky. And neither the allowed nor the earned rates of return adequately compensate investors for that risk taking. Consequently, several proposals have surfaced which suggest -

(1) increasing the allowed rates of return to levels appropriate to the risk incidence and sufficient to restore the economic vitality of the industry. (The risk compensation option.)

(2) reducing the risk through various reforms in the regulatory process to allow for more timely rate increases, automatic cost adjustments, recovery in rate base of construction work in progress and the like. (The risk reduction or risk shifting option.)

(3) turning to investment in non-regulated activities to improve overall performance and diversify risk. (The diversification option.)

(4) removing utility-type regulatory controls on power production. (The decontrol option.)

To some extent the implementation of each of these options will require favorable action at both the Federal and state level. The electric utility industry 2/ is today subject to a system of plenary regulation. It will take a great deal of effort and time to alter the existing structure in any significant way. So nothing is about to happen overnight.

I would be happy to comment on each of these options in my oral presentation or in response to questions which the subcommittee may wish to direct to me. But I would like to confine my written statement to the last of these - the decontrol option. This is easily the option attracting the most discussion and interest.

Before beginning a discussion of the deregulation option, I should disclose a considerable bias. One might think that the decontrol option is an outgrowth of the current trend to critically appraise all forms of economic regulation, such as the national efforts to deregulate trucking, airlines, railroads, and the like. But in my view, it is not a mere extention of those initiatives. True, it

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2/ For the purposes of these remarks, I mean to refer to investor-owned electric utilities when I mention the "industry" or the "electric utility industry". Public power systems also face significant financial problems but they are not of the same magnitude. Also, their structure and the regulatory environment are significantly different.

has something to do with the recognition that the present form of regulation is inadequately coping with current circumstances. I suspect, however, that the primary reason that we are today speaking of a decontrol option for electric utilities has a lot more to do with the serious financial condition of this industry and the perception of some that the decontrol option may give the industry an opportunity to improve on its financial circumstances to an extent that the political or practical constraints of the regulatory process will not allow. To those who believe that decontrol offers a cure to the industry's financial woes, I must say I respectfully but earnestly disagree.

The deregulation option presents serious questions warranting serious study and evaluation. But it must be recognized that its salutory effects or benefits, if realized, will be achieved over the very long term. The financial crisis confronted by the industry is substantial and immediate. I believe we should instead concentrate our primary focus and energies on reforming the rate regulatory process, to improve its efficiency, to improve its predictability, and to find some means for accommodating to the dynamics of the marketplace. Such a task will be itself a considerable undertaking; some of its accomplishments may be sometime off. But generally speaking, this course offers a better opportunity for getting relief in the near-term (at least for some of the most financially distressed) and greater certainty in result.

In turning to the decontrol option, let me start by raising a definitional problem. It does not seem to me that proponents of a deregulation option have been very precise in telling us exactly what they are suggesting. So I will attempt a definition for purposes of discussion. The model I will describe, it seems to me, presents the fewest problems while affording most, if not all, of the benefits that deregulation proponents envision.

Let us assume that electric generation (the production of electric energy) is to be deregulated. Assume also that only additions to capacity are to be removed from regulation. This model does not contemplate the spin-off of existing generation to a non-regulated entity which would then be free to price output and sell to such customers as it may choose.

Some proposals would deregulate all generation, but it seems to me that the transitional problems are so obvious and overwhelming that only the deregulation of increments to capacity deserves serious consideration. I will also assume that transmission and distribution remain regulated. Some deregulation scenarios contemplate converting transmission to something akin to "common carrier" status to permit optimization of the opportunities to transmit electric energy over wider geographic areas and to enhance competition. Because this is an extremely complicated matter, however, and because such a proposal would contemplate a new form of regulation and not deregulation, I would like to leave this particular nuance out of the model which we are are to discuss.

As I understand it, the question which the subcommittee seeks to answer is - What effect would the decontrol of electric power generation have on the introduction of new technologies? As you might expect, the answer I will give is that "it depends."

Today non-utility owned 3/ small power production and cogeneration facilities qualifying under the Public Utility Regulatory Policies Act (PURPA) are exempt from state and Federal rate regulation and the constraints of the Public Utility Holding Company Act. Moreover, a qualifying facility may require the electric utility in its service area to purchase the power produced and to do so at a price equal to the system's "avoided cost." This latter facet of the PURPA program provides strong incentives to the development of these diversified power sources. As a consequence, substantial entreprenurial initiatives and investments are beginning to take hold in small hydro development, biomass conversion--(particularly refuse-to-energy projects), wind, cogeneration and other qualifying applications. There is today a strong market for new technologies in these areas, although there are some constraints on scale efficiencies. In the case of cogeneration, there is no size limit, but qualifying small power production facilities may not be greater than 80 Mw and in some instances the benefits of the program are limited to facilities of 30 Mw.

3/ Utilities can participate, but their ownership interest can not be greater than 50%.

Would the decontrol option contemplate removing the regulatory aspects of the PURPA program? In other words, in a decontrolled market, could qualifying facilities continue to insist on a compelled purchase of output at a price determined in relationship to the utility's avoided cost? If not, the decontrol option may result in a diminished market for decentralized applications. On the other hand, size limitations would be removed, as would the limitations on utility ownership participation. This could expand the market for (and the market penetration of) decentralized technologies, particularly if electric utilities were permitted to price output of new facilities at the system's avoided cost (calculated without regard to the capacity to be added) and regulatory commissions determined other regulated rates for transmission and distribution without regard to the earnings from additions to generation. But those are big "ifs". We would have to see.

I think the result of decontrol is likely to be somewhat different when we come to large scale central station generation. I belong to the school that believes that we will continue to need additions of large central station power sources to satisfy future requirements and to replace aging facilities. Decentralized generation sources coupled with investments in conservation can make truly significant contributions, indeed more significant contributions than most foresaw only two years ago. They will not, however, obviate the need for, nor offset the considerable scale advantages available from, central station generation.

I find it difficult to understand who it is (other than electric utilities) other than electric that will enter the market to build central station facilities under a deregulation scenario. Such projects involve high front-end capital costs and long lead times. Typically they involve compliance with a broad range of land-use, safety and environmental controls which, however sensible or necessary, add to risks during construction and raise problems with cost containment. Presumably these facilities would have to be project financed and will require pay-outs in less than the 20-to-30-year period typical for utility property. Both the project financing and the shorter pay-out period will add to the costs.

Undoubtedly, the capital markets will demand that the power producer demonstrate a market for its output in the form of a long-term purchase power contract. And, as likely, the purchasing distribution system will require regulatory approval in advance to be assured that it will be able to pass through the purchased power costs. Here lies the problem.

Indirect regulation at the distribution level is likely to balk at the pricing terms necessary to attract capital to the investments. Unregulated power producers are not apt to agree to fixed price terms, and regulatory commissions which have been reluctant to approve indexing of prices and construction work in progress for electric utilities, would not be expected to approve their equivalent in contractual terms as a part of the purchase power agreement. Without the equivalent of cost-plus terms the project is unlikely to be financed. With them, what has the consumer gained?

Indeed, it would seem to be the usual case that non-utility project financing of central station generation will prove to be more costly than if the utility built the facility itself. Moreover, I have some concern that the necessity to resort to project financing by non-utilities would tend to limit the introduction of new technologies inasmuch as the private power producer would have to accept most of the front-end risks of technological failure. Today's regulatory system would seem to provide more avenues for distributing those risks over the total system or sharing those risks with ratepayers. It is not apparent that the purchase power contract in a deregulated market which relies on project financing would provide comparable opportunities.

If the electric utility itself were to build central station facilities in a deregulated market, it would encounter similar, although perhaps more difficult, problems. If the facility construction is to be financed through a separate entity, like the non-utility entrepreneur, project financing probably will be required. But here, because the purchase power contract is a matter of dealing between affiliates, the regulatory commissions are likely to be even stricter in reviewing the terms of the buyer's purchase decision. Moreover, they are not likely to approve price terms which appear to result in substantially higher returns on investment than the utility would have been allowed under a cost-based regulatory system. Some might, however.

Accordingly, the deregulation option may provide an opportunity (and the necessary political shelter) for an otherwise willing state regulatory commission to allow something more than cost-based rates for investment in additions to capacity. If this occurs with some frequency, the deregulation option may have more significant effects than are now apparent to me. Consequently, it is difficult to predict precisely what effect the deregulation option may have on future investment by utilities in central station power sources. But here too, it would seem that the resort to project financing would have a tendency to discourage the introduction of new technologies.

Whether the deregulation option will provide significant benefits to the nation or the electric utility industry and its customers, I really do not know. Right now I see mostly problems. 4/ That merely reflects my abounding skepticism of simple solutions.

In sum, however, it appears to me that the deregulation option presents little advantage to non-utility entrepreneurs not already available under the PURPA program, although escaping the scale limitations could be important. For electric utilities the principal advantage would seem to be that they would gain an opportunity to earn a higher-than cost based rate for investment in additions to capacity.

4/ Most of which I have not even attempted to set out in these remarks.

This is not an unimportant opportunity. But one might ask, if the regulatory authority at the distribution level is so inclined, can it not as well simply award incentive returns in a fully regulated model to provide the same advantage?

Only two years ago, the Congress was considering a proposal to mandate greater system coordination through the compulsory formation of power pools with central dispatch. Now we seem to be swinging to the polar extreme of that position. I suspect that, as is the case in most human and governmental endeavors, some moderation is in order and that neither extreme represents the optional (or politically doable) solution.

In the interim, the deregulation option deserves serious consideration because it is being advanced by serious and thoughtful people. But as I have said earlier, if it were up to me, I would focus my principal resources on efforts to reform the rate regulatory process rather than proposals to discard it and restructure the industry.

I thank you for your kind attention. I will be happy to attempt to respond to your questions.

Mr. **Fuqua**. Thank you very much, Mr. Curtis.

And now Jim Walker, commissioner of the California Energy Commission.

Mr. **Walker**. Good morning, Mr. Chairman and members. Thank you for the opportunity to be here today. I feel particularly fortunate to be a panelist on the topic of utility energy service corporation opportunities, as it is one on which the California Energy Commission has done a fair amount of work.

For those of you not familiar with the California commission, under the provisions of our far-sighted enabling legislation—signed by then Gov. Ronald Reagan—our mandate entails not only developing an independent State demand forecasting capability and conducting powerplant siting proceedings, but also includes promulgating energy conservation regulations for buildings and appliances, and biennial preparation of the State's central energy planning report for the Governor and legislature.

We have a staff of approximately 550 and a budget that includes a $50 million set of loan, commercialization and other revolving fund projects to demonstrate biomass, conservation, and other new technologies.

We have substantial resources committed in the State of California to understanding the total energy picture and particularly the utility sector.

In the 6 years of our existence that the commission has been implementing these responsibilities, we have seen startling changes in the patterns and basic premises of utility operation, a consequence of the fundamental, global economic, and political changes of the seventies. With oil and all energy prices escalating, oil supplies vulnerable, and inflation and interest rates at record highs, the utilities have been pressed to reconsider their traditional energy supply and investment strategies.

The impacts of global trends affect not just utilities but their ratepayers—all of us—as well. With the existing capital infrastructure and our own habits having been shaped in an era of cheap energy, our energy use is profligate, and the price we pay is spiraling ever upward.

As consumers we have responded to higher prices by conserving rather than consuming electricity and natural gas. This interest in conservation has created a major new demand for alternative means of achieving the desired "energy services"—comfort, heat, light, and motion—that are the end uses people need from raw fuels. When installing insulation or fluorescent light fixtures can provide a particular energy service with lower fuel use—and energy cost—consumer energy expenditures are redirected from energy suppliers to the marketers of these alternative energy service products.

This turnabout has placed the institutions that have traditionally been the monopoly suppliers of electricity and natural gas—the utilities—in novel circumstances: conservation, which they had traditionally discouraged, suddenly became a premier good but one which they had little experience at producing or marketing, and for which they held no monopoly, either natural or government-endowed. Seeing their monopoly market being stealthily eroded by

Owens-Corning, Carrier, Honeywell, Ebasco, and others, they must now compete to unsell their original product.

The alternative supply sources have been another threat to traditional monopoly of the utilities, as the Federal Energy Regulatory Commission, in implementing PURPA, established policies requiring private utilities to buy at avoided cost the power produced by small, nonutility facilities. Thus, in the 1980's the demand side of the utilities' monopoly equation is in flux due to conservation, and the production or supply-side outlook is equally unsettled by new technologies and mandatory purchase regulations.

I want to report today some of the experience we have developed in California and report on some of the California utilities' experiences in dealing with these forces.

Perhaps the most dramatic change has been the drop in demand growth. While electricity demand growth in California was 9.3 percent a year in the 1950's and 7.4 percent in the 1960's, in the 1970's the annual rate of growth was about 2.5 percent. Growth in the last 2 years has been even lower, and utility and commission forecasts now indicate it will be 1.4 percent or less in the 1980's. In 1980 the California utilities actually experienced a decline in total electricity sales, indicating that forecasts of growth even in the 1 percent range may be too high.

These forecasts are not associated with low economic growth. Our forecasts do not assume economic growth equal to the days of the 1960's, but they still invision healthy and robust economic growth.

In addition, while the transition from high growth to low growth has been a problem, low growth itself is part of the solution, not part of the problem. If demand were to grow as greatly in the 1980's as it did in the 1960's, California utilities would have to install something like 9,000 megawatts of new capacity every year. This would be an essentially unmanageable situation. It would involve, by the end of the century, 40 coal plants in California, which would be a collision course.

The lower growth has made that problem manageable. We are down to having to deal with capacity additions on the order of 1,000 megawatts a year which provide the opportunity for conservation and alternatives to make that contribution.

Even at these low or negligible growth rates, however, the California utilities will require additional generating resources. By our estimate, to meet increased demand, account for power plant retirements and power purchase contract expirations, maintain adequate reserve margins, and reduce the consumption of oil and gas used for electricity generation by 50 percent, the State will need to add 13,705 megawatts and 96,432 gigawatt hours to the 1979 baseline system by 1992.

This will allow California utilities by the early 1990's to replace 85 percent of the oil they now burn in their electric generating plants. So essentially California utilities can get off oil while keeping the lights on as a result of this lower demand growth.

The charts between pages 3 and 4 of my statement display the energy capacity situation for California utilities. These charts are drawn from the California experience and are not just quickly drawn illustrations. They were the result of 54 days of public hearings and very extensive analysis.

What they show is that the capacity available in California, given our abundance of conservation opportunities--hydro, solar, geothermal, other energy supplies, as well as the more traditional coal and nuclear options--far exceed our appetite or need over the next 12-year planned horizon.

This again brings us back to the financial picture, that we have both the responsibility and opportunity to make wise choices choose among those technologies that will maximize returns to the stockholders.

But I think the figures are startling. New facilities already operating, constructed, or under construction since 1979 will provide 70 percent of the needed capacity and 40 percent of the needed energy. Conservation alone could reduce the 1992 need for additional capacity to zero and cut in half the corresponding need for additional energy. These estimates include only conservation that would be cost-effective compared to adding new sources of supply, a criterion that virtually every California energy commission conservation program must, by statute, satisfy. The remaining need for energy could be met by developing less than 20 percent of the abundant array of available resources, which include wind, geothermal, solar, hydro, biomass fuels, synthetic fuels, and coal.

These figures are not just based on technical studies. They have been individualized down to sites for small hydro facilities, for example. Essentially they are a megawatt-by-megawatt itemization of resources available in California. They are not fictional but all have names and places associated with them.

This means that, for California, meeting these energy capacity goals is achievable. They are manageable but very challenging.

I'd like to turn now to the concept of energy service corporations as a factor in meeting these goals of the future.

These marked changes in our electricity supply and demand balance, keynoted by the increased attractiveness and availability of conservation and renewable resources, have been cause for a fundamental rethinking of the role of utilities. After the style of Harvard Business School Prof. Ted Leavitt, they have had to ask themselves, "What business are we in?" And many utilities, in California and elsewhere around the country, have begun to reformulate their own perception of their business and are attempting to evolve a new business and investment strategy, one more suited to the demand, supply, and general financial conditions of the 1980's.

This evolution has increasingly entailed "managing" demand growth, suspending new conventional base-load construction plans, and more aggressively pursuing the renewable, PURPA-type resources. They are moving "downstream of the meter" to provide their customers assistance in conserving, and integrating backward into technology development in an effort to actually bring technologies to the marketplace rather than waiting, as was traditionally true, for vendors to approach them with turnkey contracts.

The CEC reviewed and analyzed these innovative utility trends in a report released last November entitled, "Energy Service Corporations: Opportunities for California Utilities," which I'd like to discuss in a little detail at this point. I believe it was distributed to the committee.

As originally conceived, the fundamental [illegible]mise of the energy service concept is that customer demand is [illegible] for kilowatt-hours and therms but for the services derived from the electricity and gas sold by utilities, regardless of the regulatory environment. A decision should really look at the underlying life-cycle cost comparisons.

So I think independent of whether you get the rate base or other benefits, if you look at underlying economics, the efficiency improvements in some of these small-scale resources are highly competitive and as a result are a major factor in utility future plans.

Some of our previous panelists have itemized the short-term loans, the ability to recycle capital very quickly that result from investments of this nature.

I would say the financial pressures that the utilities have faced have had to some extent a silver lining. Financial pressures within the corporate bureaucracy, as evidenced by corporate vice presidents for finance, conservation managers, who are up-and-coming lights within their management structure, and many corporate planners, who began to look at the underlying macroeconomic forecasts, in effect ganged up on the old powerplant builders and said, "We don't need these, can't afford them, and there are better options that will serve our customers."

But I think the financial pressures were significant in causing, as Mr. Roe suggested, the detailed analysis of these options that resulted in some of the changes in corporate policy that we have seen.

I want to skip ahead, starting on page 10, to energy services in California—demand management strategies. The most ambitious energy service innovations the utilities are implementing are the several programs designed to assist customers in conserving through education, assistance, and financing of conservation and renewable resource measures. I believe that whether or not you call them services, they fall under that rubric.

The most advanced of these "downstream of the meter" programs is the residential conservation service program. As you are surely familiar with it already, I won't describe it here, but I do want to report the implementation progress we've had with utilities in our State, which has been excellent. We actually initiated pilot-scale implementation April 1, and are scheduled to begin statewide June 29. Virtually all California utilities are participating, including most municipals, and we are expecting over 450,000 audits to be completed annually when the program is fully in place. Regardless of the outcome of DOE's regulatory review, we intend to continue operating this very important program.

As well, the California RCS program will be implemented hand in hand with an extensive utility conservation financing program, allowing the full range of energy services to be offered to utility customers. Two ZIP—zero interest loan—pilot programs are now in operation, and the California PUC projects statewide implementation late this year. They have as well mandated a utility solar finance program with the goal of retrofitting 1 percent of gas water heating and 15 percent of electric water heating in each utility service area, which will entail over 220,000 installations.

Consumer response has been extremely favorable; the gas heater retrofit goals have been met in northern California after only 4 months, though the program was designed as a 3-year effort.

In addition to these new programs, California utilities have had extensive load management activities underway for some time. The Energy Commission in July 1979 adopted load management standards for the State's five major electric utilities. The standards required utilities to establish load management programs, including residential central air-conditioner and water heater cycling, swimming pool filter pump timeclock adjustments, and audits/assistance for commercial customers.

The utilities' programs have been approved by the Commission, and both the swimming pump and commercial audit program are in full-scale implementation. The residential cycling program involves new applications of electronic hardware and is currently in pilot implementation and receiving enthusiastic customer response; nearly 100,000 remote cyclers have already been installed including 60,000 in the P.G. & E. service area alone. Overall, the programs are expected to result in energy savings of 8,900 GWH and capacity reductions of 1,638 MW by 1985. The net present value of the program is projected at nearly $5.5 billion through 1989.

These and other utility customer service programs have been designed to equip customers with the information and assistance they need to make the individual decisions which will most cheaply provide for their own energy service needs. And they are giving utilities on-the-job training for their new roles in energy service delivery.

Progress in supply-side implementation of energy service options is particularly exciting and I believe demonstrates the feasibility of developing the abundant alternative resources identified in the figures earlier. The increased utility interest in the renewable alternatives is typified by the actions of the Southern California Edison Co., which recently announced a major policy shift toward renewables. William R. Gould, SCE board chairman and chief executive officer stated:

> It is the policy of Edison to devote our corporate resources to the accelerated development of a wide variety of future electrical power sources which are renewable rather than finite . . . . As a result of some significant successes in a number of research and development areas, the company now believes that some forms of power which a few years ago were speculative or unproven have progressed to the point that they can be aggressively developed and relied upon to provide a significant part of the electricity to supply the additional needs of our customers later this decade.

Moreover, SCE's resource plan of fall 1980 incorporates over 1,900 MW of renewable/alternative resources to be developed by 1990. Pacific Gas & Electric as well has announced that 54 percent, or 3,516 MW, of additions planned during the 1980's will be preferred resources under California energy policy—hydro, geothermal, cogeneration, and wind.

Implementation of the utility proposed supply plans is already underway. Utilities's industries today cogenerate almost 500 MW of electric power, including over 150 MW in forestry and agriculture. The 900 MW of geothermal in current production by P.G. & E. at the Geysers is the largest geothermal operation in the world; an additional 300 MW is under construction, and development will continue through this century, to 2,000 MW. The State has over 700 MW of small hydroelectric power operating and an additional 1,000 MW potential. Both P.G. & E. and SCE have interest in solar photovoltaic production technologies, and SCE has a 2-MW unit installed. Another solar technology, the 10 MW DOE "Solar One" electric production facility, will begin operation in 1982. Southern California Edison and others are planning a 5-MW solar pond at the Salton Sea by 1984.

Progress in wind applications has been truly phenomenal—SCE has a 3-MW wind turbine in operation now and has signed letters of intention for 25 MW more. P.G. & E. has ordered a 2.5-MW Boeing turbine for siting in 1982 and is working with Windfarms, Ltd., to develop a 350-MW farm on land P.G. & E. acquired expressly for its wind resource characteristics. Two other private companies, U.S. Windpower and Fayette Manufacturing, have both received construction permits for 10 MW developments and are negotiating purchase contracts with P.G. & E. at this time.

I will not review everything else that is contained in my testimony. I will point out that California is trying to be a major partner in these activities. I mentioned the $50 million the Energy Commission has set aside for many of these projects. There has also been recently established a $200 million bond authority to assist solar, biomass, wind, geothermal, small hydroelectric, and other projects which will reduce the use of fossil and nuclear fuels.

In addition, in the latest budget just passed by the State legislature on June 15, in spite of the impact of proposition 13 on local revenues and the need for careful balancing of our budget, the State legislature did see fit to approve $2 million in matching funds for SMUD's 100 MW central station photovoltaic installation, $250,000 for an SCE solar pond facility, and over $1.5 million for cogeneration in our university facilities.

Some concluding thoughts: I think one of the things I bring away from looking at the utility industry is the importance of a continuing partnership in this area.

I would emphasize, for example, that while the examples I have cited are from California, similar activities and trends have taken place around the country.

All these activities I think fall under the concept of having utilities first maintain themselves as viable institutions and enterprises. This, I think, is where many of the concerns about the long-term health of utilities are based. We agree the utilities should have a role in meeting the broad energy needs of California consumers for the foreseeable future. We cannot see them being replaced by any other institution, though I think their role can be changed and complemented over time.

I think that the utilities will have to develop significantly in terms of their management structure and their management skills. This is not to say that management has been bad in the past, because I don't believe it has. But the situation and the environment has changed so dramatically that the same management skills that were useful in getting four or five coal plants approved are going to be different from those required to manage 450,000 audits a year or oversee all the solar installations, which are only the opening wedge.

I think Canada and Mexico will be involved with U.S. utilities in power brokering on a continental scale. Many other aspects will be changing the way they have traditionally done business.

At the same time I think, while it is not in vogue to be an advocate of Government in present times, the progress to date has very much depended on such partnership. The Federal Government, for example, has been absolutely central in setting the broad policy context through NECPA, PURPA, the ESA, and others. The States have been equally essential in their role of translating broad federal constructs into workable, equitable programs suited to unique State needs and circumstances.

Especially crucial State responsibilities remain to be met in the coming period: monitoring, evaluation, and program redesign. In California we have found that a strong State role in direct regulation is also an important supplement to broad Federal mandates.

This week, for example, we will be adopting our second generation building standards for new residential construction, which will assure that our future housing stock will use only a quarter of the energy used in 1975-type construction. A State mandate for conservation retrofit of the inefficient existing housing very nearly passed both houses of our legislature last session, and a similar bill is being considered this year.

Local governments in our State have on occasion themselves taken a strong lead in establishing local energy efficiency requirements, and have also been successful in creating municipal solar utilities to advise and offer financing to customers interested in solar and other renewable resource applications.

Our experience as a regulatory commission has shown us repeatedly that little can be accomplished without a cooperative partnership with the utilities or industries affected. The magnitude of the R. & D. task is generally beyond the capability of one company or utility and requires the support not only of the utilities and industry but of Congress and the DOE. To some extent, these ventures have been successful because the private-sector partners themselves have had fundamental commitment to the new service strategies and technologies.

But I think at the Federal level we will also see a continuing need for Federal support of some large-scale commercial demonstrations. I think this committee has played a critical role in the past, and I trust it will continue to play a critical role in developing technologies that then have commercial applications in the utility sectors.

I think if I had to summarize, our main task now is to develop a partnership between Government and industry that will persuade, first of all, the ratepayers that they may have to pay a little more now to make wise investments that will get us off the OPEC-driven treadmill. And similarly we will have to persuade investors in the capital markets that the utilities have the management skills and vision to provide viable long-term services. And, if so, I don't see them as being in a state of crisis. I believe there is light at the end of the tunnel.

Thank you.

[The prepared statement of Mr. Walker follows.]

TESTIMONY OF

JAMES A. WALKER

I. INTRODUCTION

GOOD MORNING. MR. CHAIRMAN AND MEMBERS, THANK YOU FOR THE OPPORTUNITY TO BE HERE TODAY. I FEEL PARTICULARLY FORTUNATE TO BE A PANELIST ON THE TOPIC OF UTILITY ENERGY SERVICE CORPORATION OPPORTUNITIES, AS IT IS ONE ON WHICH THE CALIFORNIA ENERGY COMMISSION HAS DONE A FAIR AMOUNT OF WORK. FOR THOSE OF YOU NOT FAMILIAR WITH THE CALIFORNIA COMMISSION, UNDER THE PROVISIONS OF OUR FAR-SIGHTED ENABLING LEGISLATION (SIGNED BY THEN GOVERNOR RONALD REAGAN), OUR MANDATE ENTAILS NOT ONLY DEVELOPING AN INDEPENDENT STATE DEMAND FORECASTING CAPABILITY AND CONDUCTING POWER PLANT SITING PROCEEDINGS, BUT ALSO INCLUDES PROMULGATING ENERGY CONSERVATION REGULATIONS FOR BUILDINGS AND APPLIANCES, AND BIENNIAL PREPARATION OF THE STATES' CENTRAL ENERGY PLANNING REPORT FOR THE GOVERNOR AND LEGISLATURE.

IN THE SIX YEARS THE COMMISSION HAS BEEN IMPLEMENTING THESE RESPONSIBILITIES WE HAVE SEEN STARTLING CHANGE IN THE PATTERNS AND BASIC PREMISES OF UTILITY OPERATION, A CONSEQUENCE OF THE FUNDAMENTAL, GLOBAL ECONOMIC AND POLITICAL CHANGES OF THE SEVENTIES. WITH OIL AND ALL ENERGY PRICES ESCALATING, OIL SUPPLIES VULNERABLE, AND INFLATION AND INTEREST RATES AT RECORD HIGHS, THE UTILITIES HAVE BEEN PRESSED TO RECONSIDER THEIR TRADITIONAL ENERGY SUPPLY AND INVESTMENT STRATEGIES.

THE IMPACTS OF GLOBAL TRENDS AFFECT NOT JUST UTILITIES BUT THEIR RATEPAYERS--ALL OF US--AS WELL. WITH THE EXISTING CAPITAL INFRASTRUCTURE AND OUR OWN HABITS HAVING BEEN SHAPED IN ERA OF CHEAP ENERGY, OUR ENERGY USE IS PROFLIGATE, AND THE PRICE WE PAY IS SPIRALLING EVER-UPWARD.

AS CONSUMERS WE HAVE RESPONDED TO HIGHER PRICES BY CONSERVING RATHER THAN CONSUMING ELECTRICITY AND NATURAL GAS. THIS INTEREST IN CONSERVATION HAS CREATED A MAJOR NEW DEMAND FOR ALTERNATIVE MEANS OF ACHIEVING THE DESIRED "ENERGY SERVICES"--COMFORT, HEAT, LIGHT AND MOTION--THAT ARE THE END USES PEOPLE NEED FROM RAW FUELS. WHEN INSTALLING INSULATION OR FLUORESCENT LIGHT FIXTURES CAN PROVIDE A PARTICULAR ENERGY SERVICE WITH LOWER FUEL USE (AND ENERGY COST), CONSUMER ENERGY EXPENDITURES ARE REDIRECTED FROM ENERGY SUPPLIERS TO THE MARKETERS OF THESE ALTERNATIVE ENERGY SERVICE PRODUCTS.

THIS TURNABOUT HAS PLACED THE INSTITUTIONS THAT HAVE TRADITIONALLY BEEN THE MONOPOLY SUPPLIERS OF ELECTRICITY AND NATURAL GAS--THE UTILITIES--IN NOVEL CIRCUMSTANCES: "CONSERVATION," WHICH THEY HAD TRADITIONALLY DISCOURAGED, SUDDENLY BECAME A PREMIER GOOD BUT ONE WHICH THEY HAD LITTLE EXPERIENCE AT PRODUCING OR MARKETING, AND FOR WHICH THEY HELD NO MONOPOLY, EITHER NATURAL OR GOVERNMENT ENDOWED. SEEING THEIR MONOPOLY MARKET BEING STEALTHILY ERODED BY OWENS-CORNING, CARRIER, HONEYWELL, EBASCO, AND OTHERS, THEY MUST NOW COMPETE TO "UNSELL" THEIR ORIGINAL PRODUCT.

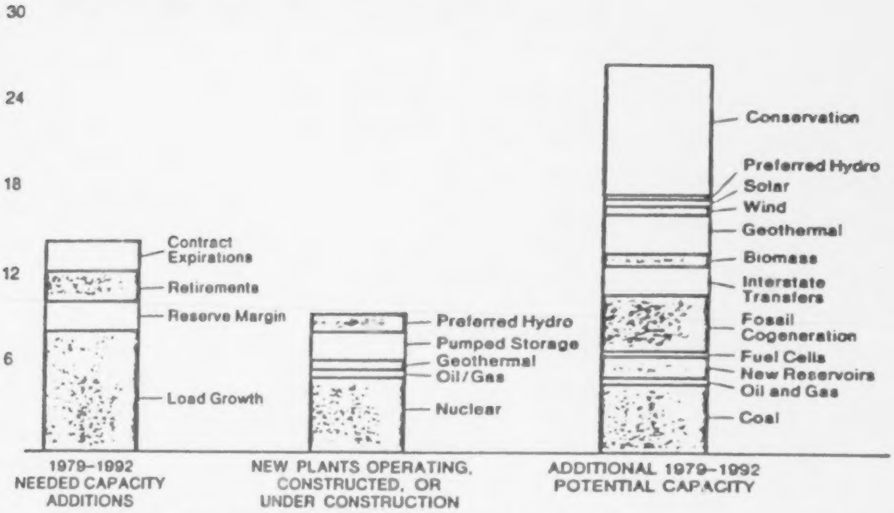
THE ALTERNATIVE SUPPLY SOURCES HAVE BEEN ANOTHER THREAT TO TRADITIONAL MONOPOLY OF THE UTILITIES, AS THE FEDERAL ENERGY REGULATORY COMMISSION, IN IMPLEMENTING PURPA, ESTABLISHED POLICIES REQUIRING PRIVATE UTILITIES TO BUY AT AVOIDED COST THE POWER PRODUCED BY SMALL, NON-UTILITY FACILITIES. THUS, IN THE 1980s THE DEMAND SIDE OF THE UTILITIES' MONOPOLY EQUATION IS IN FLUX DUE TO CONSERVATION AND THE PRODUCTION OR SUPPLY SIDE OUTLOOK IS EQUALLY UNSETTLED BY NEW TECHNOLOGIES AND MANDATORY PURCHASE REGULATIONS.

II. CALIFORNIA'S ELECTRICITY DEMAND AND SUPPLY BALANCE

THE MARKED CHANGES THESE TRENDS HAVE BROUGHT IN CALIFORNIA ARE ILLUSTRATED BY THE FOLLOWING FIGURES. WHILE ELECTRICITY DEMAND GROWTH WAS 9.3 AND 7.4% IN THE 1950's AND 1960's RESPECTIVELY, THE ANNUAL RATE OF GROWTH IN THE SEVENTIES WAS ABOUT 2½%. GROWTH IN THE LAST TWO YEARS HAS BEEN EVEN LOWER, AND UTILITY AND COMMISSION FORECASTS NOW INDICATE IT WILL BE 1.4% OR LESS IN THE 1980s. IN 1980, THE CALIFORNIA UTILITIES ACTUALLY EXPERIENCED A DECLINE IN TOTAL ELECTRICITY SALES, INDICATING THAT FORECASTS OF GROWTH EVEN IN THE 1% RANGE MAY BE TOO HIGH.

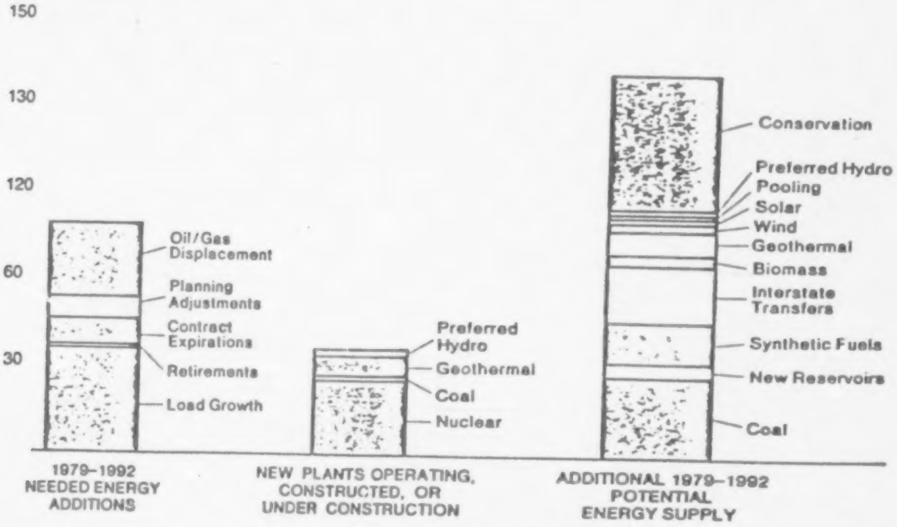
EVEN AT THESE LOW OR NEGLIGIBLE GROWTH RATES, HOWEVER, THE CALIFORNIA UTILITIES WILL REQUIRE ADDITIONAL GENERATING RESOURCES. BY OUR ESTIMATE, TO MEET INCREASED DEMAND, ACCOUNT FOR POWER PLANT RETIREMENTS AND POWER PURCHASE

FIGURE 5-8
1992 STATEWIDE ELECTRIC POWER FIRM CAPACITY
(Thousand Megawatts)



California needs 13,705 MW of new capacity by 1992 to ensure reliable electric service (left). Much of this needed capacity is already under construction (middle). Over 26,000 MW of additional conservation and supply sources, including many preferable alternative technologies, are also available to meet these needs (right).

FIGURE 5-9
1992 STATEWIDE ELECTRIC ENERGY
(Thousand Gigawatt-hours)

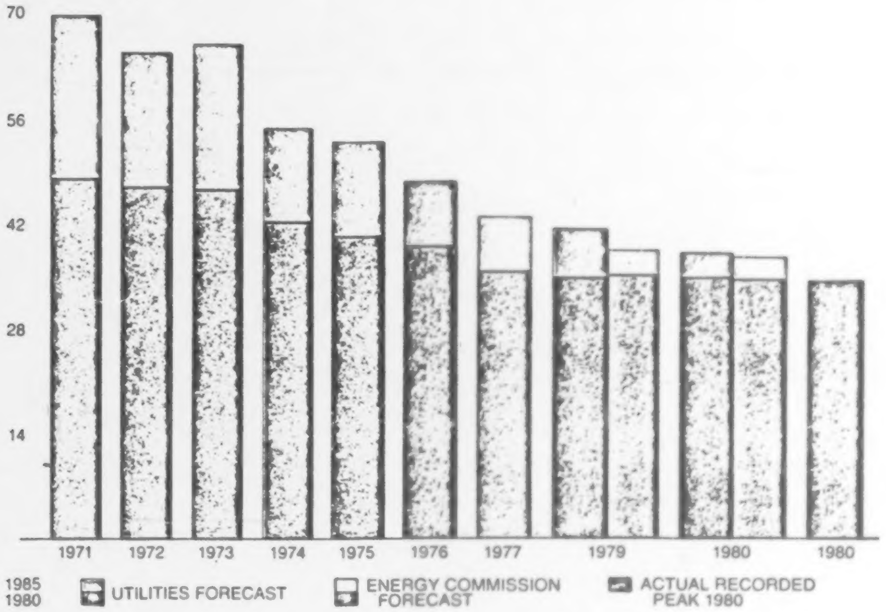


There are also more than enough available options to meet California's electric energy needs. These needs include meeting demand growth, and also reducing fuel use in oil-and gas-fired power plants by at least 50 percent by 1992.

TABLE 5-1
FORECASTS OF ELECTRICITY PEAK DEMAND AND GROWTH RATES
(Megawatts)

WHO MADE THE FORECAST AND WHEN	1980	1985	AVERAGE ANNUAL GROWTH RATES (%)
Actual Recorded Peak	35,100	—	—
Energy Commission 1980	35,202	37,866	1.47
Utilities 1980	35,211	38,376	1.74
Energy Commission 1979	35,587	38,790	1.74
Utilities 1979	35,211	41,542	3.30
Energy Commission 1977	36,005	43,307	3.76
Utilities 1976	39,150	47,905	4.12
Utilities 1975	40,215	52,883	5.63
Utilities 1974	42,370	54,779	5.27
Utilities 1973	47,021	65,850	6.97
Utilities 1972	47,267	64,827	6.52
Utilities 1971	48,269	68,922	7.38

FIGURE 5-2
ELECTRICITY PEAK DEMAND FORECASTS 1971-1980
(Thousand Megawatts)



CONTRACT EXPIRATIONS, MAINTAIN ADEQUATE RESERVE MARGINS, AND REDUCE THE CONSUMPTION OF OIL AND GAS USED FOR ELECTRICITY GENERATION BY 50 PERCENT, THE STATE WILL NEED TO ADD 13,705 MEGAWATTS (MW) AND 96,432 GIGAWATTS (GWH) TO THE 1979 BASELINE SYSTEM BY 1992.

THE ACCOMPANYING FIGURE ALSO ILLUSTRATES THE STATE'S ABUNDANT POTENTIAL FOR MEETING THESE REQUIREMENTS FOR ADDITIONAL RESOURCES. NEW FACILITIES ALREADY OPERATING, CONSTRUCTED, OR UNDER CONSTRUCTION SINCE 1979 WILL PROVIDE 70% OF THE NEEDED CAPACITY AND 40% OF THE NEEDED ENERGY. CONSERVATION ALONE COULD REDUCE THE 1992 NEED FOR ADDITIONAL CAPACITY TO ZERO AND CUT IN HALF THE CORRESPONDING NEED FOR ADDITIONAL ENERGY. (THESE ESTIMATES INCLUDE ONLY CONSERVATION THAT WOULD BE COST-EFFECTIVE COMPARED TO ADDING NEW SOURCES OF SUPPLY, A CRITERION THAT VIRTUALLY EVERY CALIFORNIA ENERGY COMMISSION CONSERVATION PROGRAM MUST, BY STATUTE, SATISFY.) MEETING THE REMAINING NEED FOR ENERGY COULD BE MET BY DEVELOPING LESS THAN 20% OF THE ABUNDANT ARRAY OF AVAILABLE RESOURCES, WHICH INCLUDE WIND, GEOTHERMAL, SOLAR HYDRO, BIOMASS FUELS, SYNTHETIC FUELS, AND COAL.

III. UTILITY "ENERGY SERVICE" INVESTMENT STRATEGIES

THESE MARKED CHANGES IN OUR ELECTRICITY SUPPLY AND DEMAND BALANCE, KEYNOTED BY THE INCREASED ATTRACTIVENESS AND AVAILABILITY OF CONSERVATION AND RENEWABLE RESOURCES, HAVE BEEN CAUSE FOR A

FUNDAMENTAL RETHINKING OF THE ROLE OF UTILITIES. AFTER THE STYLE OF HARVARD BUSINESS SCHOOL PROFESSOR TED LEAVITT, THEY HAVE HAD TO ASK THEMSELVES "WHAT BUSINESS ARE WE IN?" AND MANY UTILITIES, IN CALIFORNIA AND ELSEWHERE AROUND THE COUNTRY HAVE BEGUN TO REFORMULATE THEIR OWN PERCEPTION OF THEIR BUSINESS AND ARE ATTEMPTING TO EVOLVE A NEW BUSINESS AND INVESTMENT STRATEGY, ONE MORE SUITED TO THE DEMAND, SUPPLY, AND GENERAL FINANCIAL CONDITIONS OF THE EIGHTIES. THIS EVOLUTION HAS INCREASINGLY ENTAILED "MANAGING" DEMAND GROWTH, SUSPENDING NEW CONVENTIONAL BASE LOAD CONSTRUCTION PLANS, AND MORE AGGRESSIVELY PURSUING THE RENEWABLE, PURPA-TYPE RESOURCES. THEY ARE MOVING "DOWNSTREAM OF THE METER" TO PROVIDE THEIR CUSTOMERS ASSISTANCE IN CONSERVING, AND INTEGRATING BACKWARD INTO TECHNOLOGY DEVELOPMENT IN AN EFFORT TO ACTUALLY BRING TECHNOLOGIES TO THE MARKET PLACE RATHER THAN WAITING FOR VENDORS TO APPROACH THEM WITH TURNKEY CONTRACTS.

THE CEC REVIEWED AND ANALYZED THESE INNOVATIVE UTILITY TRENDS IN A REPORT RELEASED LAST NOVEMBER, ENTITLED ENERGY SERVICE CORPORATIONS: OPPORTUNITIES FOR CALIFORNIA UTILITIES, WHICH I'D LIKE TO DISCUSS IN A LITTLE DETAIL AT THIS POINT.

AS ORIGINALLY CONCEIVED, THE FUNDAMENTAL PREMISE OF THE "ENERGY SERVICE" CONCEPT IS THAT CUSTOMER DEMAND IS NOT FOR KW HOURS AND THERMS, BUT FOR THE SERVICES DERIVED FROM THE ELECTRICITY AND GAS SOLD BY UTILITIES. AS OUTLINED IN THE ENERGY COMMISSION

REPORT, THE UTILITY ENERGY SERVICE CORPORATION STRATEGY SEEKS TO MEET THESE ENERGY SERVICE DEMANDS BY INTEGRATING THE CHEAPEST MIX OF EFFICIENCY IMPROVEMENTS, SUCH AS INSULATING BUILDINGS OR RENOVATING STREET LIGHTS, WITH ALTERNATIVE RESOURCE GENERATION AND EXISTING SYSTEM RESOURCES. SPECIFIC UTILITY ACTIVITIES UNDER THIS CONCEPT COULD INCLUDE ASSISTING CUSTOMERS IN CONSERVATION AND RENEWABLE RESOURCE UTILIZATION, DEVELOPING ALTERNATIVE GENERATION UNDER THE COMPETITIVE CONDITIONS ESTABLISHED BY SECTION 210 OF THE PUBLIC UTILITIES REGULATORY POLICY ACT, AND FINANCING AND MARKETING CONSERVATION AND ALTERNATIVES WHERE APPROPRIATE. IN ALL THESE AREAS, THE UTILITIES WOULD BE USING THEIR EXISTING INFRASTRUCTURE, SUCH AS DIRECT CUSTOMER CONTACT AND CONFIDENCE, BILLING, TRANSMISSION AND SO ON, TO INCREASE THE RATE OF DEVELOPMENT OF CONSERVATION AND ALTERNATIVE RESOURCES AND TO REDUCE TRANSACTION COSTS.

THIS ENERGY SERVICE INVESTMENT STRATEGY CAN HAVE QUITE SUBSTANTIAL FINANCIAL AND ECONOMIC BENEFITS FOR BOTH UTILITIES AND CONSUMERS, AS IT:

- REDUCES OIL CONSUMPTION FASTER THAN CONVENTIONAL LONG-LEAD TIME CONSTRUCTION;
- REDUCES TOTAL COST OF ENERGY (AND ENERGY SERVICES);
- REDUCES THE AMOUNT OF AFDC REQUIRED PER UNIT OF ENERGY PRODUCTION;

- REDUCES UTILITY CAPITAL REQUIREMENTS THROUGH FINANCING RATHER THAN OWNING ENERGY DEVICES; AND
- OPENS POTENTIAL NEW BUSINESS OPPORTUNITIES FOR UTILITIES, LIMITED, OR COURSE, BY THE NEED TO MAINTAIN COMPETITION.

TO BE MORE SPECIFIC, UTILITIES ARE BETTER ABLE TO FINANCE CONSERVATION INVESTMENTS THAN CONVENTIONAL POWER PLANTS FOR TWO REASONS: FIRST, THERE IS RELATIVELY LITTLE TIME LAG BETWEEN THE TIME WHEN A CONSERVATION INVESTMENT IS MADE AND WHEN IT BECOMES ELIGIBLE FOR RECOVERY IN RATES. THUS, EVEN THOUGH A CAPITAL INVESTMENT IS MADE, THE UTILITY DOES NOT HAVE TO FINANCE IT AS CONSTRUCTION WORK IN PROGRESS FOR LONG PERIODS OF TIME; CASH FLOW TO PAY DEBT IS RAPIDLY RECEIVED. SECOND, CONSERVATION FINANCING PROGRAMS, EXCEPT FOR DIRECT UTILITY INVESTMENT WITH NO REPAYMENT BY THE PARTICIPANT, WILL "RECYCLE" CAPITAL IN LOAN REPAYMENTS. RATEPAYER SUPPORT FOR THE CONSERVATION IS THUS MUCH LESS THAN FOR CONVENTIONAL PROJECTS BECAUSE THE LOANS ARE REPAID EVEN THOUGH THE CONSERVATION INVESTMENTS CONTINUE TO CONSERVE ENERGY INDEFINITELY.

THERE ARE SEVERAL ADVANTAGES TO BE GAINED BY UTILITY MARKETING

OF CONSERVATION AND ALTERNATIVE ENERGY EQUIPMENT. THEY EXPAND THEIR ECONOMIC BASES BEYOND SALES OF ELECTRICITY AND GAS, WHICH ARE OF INCREASING FINANCIAL RISK, INTO OTHER AREAS LESS RISKY. THIS DIVERSIFICATION COULD HAVE THE ADDITIONAL ADVANTAGE TO THE UTILITY OF ESTABLISHING CORPORATE ACTIVITIES NOT SUBJECT TO TRADITIONAL REGULATION, WHERE HIGHER PROFITS MAY BE EARNED.

MORE AGGRESSIVE UTILITY CONSERVATION EFFORTS SHOULD ALSO MITIGATE CONSUMER RESENTMENT OF RATE HIKES AND WILL GENERALLY IMPROVE CUSTOMER RESPONSE TO MANDATED AUDIT PROGRAMS SUCH AS THE RESIDENTIAL CONSERVATION SERVICE (RCS) AND UTILITY FINANCING PROGRAMS. MARKETING OF LOAD MANAGEMENT OR ALTERNATIVE ENERGY DEVICES SUCH AS COGENERATION SYSTEMS TO INDUSTRIAL CUSTOMERS CAN ALSO FACILITATE UTILITY ACTIVITIES TO PROMOTE THESE ALTERNATIVE ENERGY SOURCES.

PURCHASE OF POWER UNDER PURPA SECTION 210 PROVISIONS WILL BE OF SHORT AND LONG-TERM BENEFIT, AS IT WILL REDUCE THE UTILITIES' CAPITAL REQUIREMENTS, THUS EASING THE FINANCIAL STRAIN ON STOCKHOLDERS AND BONDHOLDERS. THOUGH NOT PROVIDING RATEPAYERS WITH CHEAPER ENERGY DIRECTLY (BECAUSE PRICES WILL BE SET AT THE AVOIDED COSTS), PURCHASES ALLOW CONSUMERS IMPORTANT INDIRECT BENEFITS FROM REDUCED OIL CONSUMPTION (SUCH AS LOWER GENERAL INFLATION, REDUCED

RISK OF SUPPLY DISRUPTION, AND IMPROVED AIR QUALITY). MORE IMPORTANTLY, RATEPAYERS GAIN INDIRECTLY SINCE IMPROVEMENTS IN UTILITY QUALITY OF EARNINGS (RESULTING FROM REDUCED FINANCING NEEDS WHICH IN TURN REDUCE REQUIRED RETURNS ON EQUITY AND DEBT) SHOULD DECREASE UTILITY DEMANDS FOR EXTRAORDINARY RATE RELIEF MEASURES SUCH AS CWIP IN THE RATE BASE, TAX NORMALIZATION, AND HIGHER RATE OF RETURN TO FINANCE CONVENTIONAL POWER PLANTS. PURCHASES CAN ALSO BENEFIT STOCKHOLDERS AND RATEPAYERS IN CASES WHERE THE TECHNOLOGY IS NOT FULLY DEVELOPED, AS NON-UTILITY DEVELOPERS ASSUME SOME OF THE TECHNICAL RISK FOR WIND MACHINES AND OTHER INNOVATIVE TECHNOLOGIES.

AS I MENTIONED EARLIER, UTILITIES THEMSELVES HAVE BECOME AWARE OF THE MAGNITUDE OF THESE POTENTIAL BENEFITS, AND IN FACT ARE MOVING RELATIVELY RAPIDLY TOWARD ENERGY SERVICE ACTIVITIES SUCH AS THOSE OUTLINED IN THE PRECEDING SECTION. THE COMMISSION'S ENERGY SERVICE CORPORATION REPORT REVIEWS IMPLEMENTATION PROGRAMS IN SOME DETAIL, BUT I'D LIKE AT THIS TIME TO BRIEFLY HIGHLIGHT THE CURRENT STATUS OF THE CALIFORNIA EFFORTS.

IV. ENERGY SERVICES IN CALIFORNIA--"DEMAND MANAGEMENT" STRATEGIES

THE MOST AMBITIOUS ENERGY SERVICE INNOVATIONS THE UTILITIES ARE IMPLEMENTING ARE THE SEVERAL PROGRAMS DESIGNED TO ASSIST CUSTOMERS IN CONSERVING THROUGH EDUCATION, ASSISTANCE, AND FINANCING OF CONSERVATION AND RENEWABLE RESOURCE MEASURES.

THE MOST ADVANCED OF THESE "DOWNSTREAM OF THE METER" PROGRAMS IS THE RESIDENTIAL CONSERVATION SERVICE (RCS) PROGRAM. AS YOU ARE SURELY FAMILIAR WITH IT ALREADY I WON'T DESCRIBE IT HERE, BUT I DO WANT TO REPORT THE IMPLEMENTATION PROGRESS WE'VE HAD WITH UTILITIES IN OUR STATE, WHICH HAS BEEN EXCELLENT. WE ACTUALLY INITIATED PILOT SCALE IMPLEMENTATION APRIL 1, AND ARE SCHEDULED TO BEGIN STATEWIDE JUNE 29. VIRTUALLY ALL CALIFORNIA UTILITIES ARE PARTICIPATING, INCLUDING MOST MUNICIPALS, AND WE ARE EXPECTING OVER 450,000 AUDITS TO BE COMPLETED ANNUALLY WHEN THE PROGRAM IS FULLY IN PLACE. REGARDLESS OF THE OUTCOME OF DOE'S REGULATORY REVIEW, WE INTEND TO CONTINUE OPERATING THIS VERY IMPORTANT PROGRAM

AS WELL, THE CALIFORNIA RCS PROGRAM WILL BE IMPLEMENTED HAND-IN-HAND WITH AN EXTENSIVE UTILITY CONSERVATION FINANCING PROGRAM, ALLOWING THE FULL RANGE OF ENERGY SERVICES TO BE OFFERED TO UTILITY CUSTOMERS. TWO ZIP (ZERO INTEREST LOAN) PILOT PROGRAMS ARE NOW IN OPERATION, AND THE CALIFORNIA PUC PROJECTS STATEWIDE IMPLEMENTATION LATE THIS YEAR. THEY HAVE AS WELL MANDATED A UTILITY SOLAR FINANCE PROGRAM WITH THE GOAL OF RETROFITTING ONE PERCENT OF GAS WATER HEATING AND 15 PERCENT OF ELECTRIC WATER HEATING IN EACH UTILITY SERVICE AREA, WHICH WILL ENTAIL OVER 220,000 INSTALLATIONS.

CONSUMER RESPONSE HAS BEEN EXTREMELY FAVORABLE; THE GAS HEATER RETROFIT GOALS HAVE BEEN MET IN NORTHERN CALIFORNIA AFTER ONLY FOUR MONTHS, THOUGH THE PROGRAM WAS DESIGNED AS A THREE YEAR EFFORT.

IN ADDITION TO THESE NEWER PROGRAMS, CALIFORNIA UTILITIES HAVE HAD EXTENSIVE LOAD MANAGEMENT ACTIVITIES UNDERWAY FOR SOME TIME. THE ENERGY COMMISSION IN JULY 1979 ADOPTED LOAD MANAGEMENT STANDARDS FOR THE STATE'S FIVE MAJOR ELECTRIC UTILITIES. THE STANDARDS REQUIRED UTILITIES TO ESTABLISH LOAD MANAGEMENT PROGRAMS, INCLUDING RESIDENTIAL CENTRAL AIR CONDITIONER AND WATER HEATER CYCLING, SWIMMING POOL FILTER PUMP TIMECLOCK ADJUSTMENTS, AND AUDITS/ASSISTANCE FOR COMMERCIAL CUSTOMERS. THE UTILITIES' PROGRAMS HAVE BEEN APPROVED BY THE COMMISSION, AND BOTH THE SWIMMING PUMP AND COMMERCIAL AUDIT PROGRAM ARE IN FULL-SCALE IMPLEMENTATION THE RESIDENTIAL CYCLING PROGRAM INVOLVES NEW APPLICATIONS OF ELECTRONIC HARDWARE AND IS CURRENTLY IN PILOT IMPLEMENTATION AND RECEIVING ENTHUSIASTIC CUSTOMER RESPONSE; NEARLY 100,000 REMOTE CYCLERS HAVE ALREADY BEEN INSTALLED INCLUDING 60,000 IN THE PG&E SERVICE AREA ALONE. OVERALL THE PROGRAMS ARE EXPECTED TO RESULT IN ENERGY SAVINGS OF 8900 GWH AND CAPACITY REDUCTIONS OF 1638 MW BY 1985. THE NET PRESENT VALUE OF THE PROGRAM IS PROJECTED AT NEARLY $5.5 BILLION THROUGH 1989.

THESE AND OTHER UTILITY CUSTOMER SERVICE PROGRAMS HAVE BEEN DESIGNED TO EQUIP CUSTOMERS WITH THE INFORMATION AND ASSISTANCE THEY NEED TO MAKE THE INDIVIDUAL DECISIONS WHICH WILL MOST CHEAPLY PROVIDE FOR THEIR OWN ENERGY SERVICE NEEDS. AND, THEY ARE GIVING UTILITIES ON-THE-JOB TRAINING FOR THEIR NEW ROLES IN ENERGY SERVICE DELIVERY.

V. ENERGY SERVICES IN CALIFORNIA: SUPPLY-SIDE IMPLEMENTATION

PROGRESS IN SUPPLY-SIDE IMPLEMENTATION OF ENERGY SERVICE OPTIONS IS PARTICULARLY EXCITING, AND I BELIEVE DEMONSTRATES THE FEASIBILITY OF DEVELOPING THE ABUNDANT ALTERNATIVE RESOURCES IDENTIFIED IN THE FIGURES EARLIER. THE INCREASED UTILITY INTEREST IN THE RENEWABLE ALTERNATIVES IS TYPIFIED BY THE ACTIONS OF THE SOUTHERN CALIFORNIA EDISON COMPANY, WHICH RECENTLY ANNOUNCED A "MAJOR POLICY SHIFT TOWARD RENEWABLES". NOTES WILLIAM R. GOULD, SCE BOARD CHAIRMAN AND CHIEF EXECUTIVE OFFICER:

> "IT IS THE POLICY OF EDISON TO DEVOTE OUR CORPORATE RESOURCES TO THE ACCELERATED DEVELOPMENT OF A WIDE VARIETY OF FUTURE ELECTRICAL POWER SOURCES WHICH ARE RENEWABLE RATHER THAN FINITE.... AS A RESULT OF SOME SIGNIFICANT SUCCESSES IN A NUMBER OF RESEARCH AND DEVELOPMENT AREAS, THE COMPANY NOW BELIEVES THAT SOME FORMS OF POWER WHICH A FEW YEARS AGO WERE SPECULATIVE OR UNPROVEN HAVE PROGRESSED TO THE POINT THAT THEY CAN BE AGGRESSIVELY DEVELOPED AND RELIED UPON TO PROVIDE A SIGNIFICANT PART OF THE ELECTRICITY TO SUPFLY THE ADDITIONAL NEEDS OF OUR CUSTOMERS LATER THIS DECADE".

MOREOVER, SCE'S RESOURCE PLAN OF FALL 1980 INCORPORATES OVER 1900 MW OF RENEWABLE/ALTERNATIVE RESOURCES TO BE DEVELOPED BY 1990. PACIFIC GAS AND ELECTRIC AS WELL HAS ANNOUNCED THAT

"FIFTY FOUR PERCENT (OR 3516 MW) OF ADDITIONS PLANNED DURING THE 1980'S WILL BE PREFERRED RESOURCES UNDER CALIFORNIA ENERGY POLICY - HYDRO, GEOTHERMAL, COGENERATION AND WIND".

IMPLEMENTATION OF THE UTILITY PROPOSED SUPPLY PLANS IS ALREADY UNDERWAY. CALIFORNIA'S INDUSTRIES TODAY COGENERATE ALMOST 500 MW OF ELECTRIC POWER, INCLUDING OVER 150 MW IN FORESTRY AND AGRICULTURE. THE 900 MW OF GEOTHERMAL IN CURRENT PRODUCTION BY PG&E AT THE GEYSERS IS THE LARGEST GEOTHERMAL OPERATION IN THE WORLD; AN ADDITONAL 300 MW IS UNDER CONSTRUCTION, AND DEVELOPMENT WILL CONTINUE THROUGH THIS CENTURY. TO 2000 MW. THE STATE HAS OVER 700 MW OF SMALL HYDROELECTRIC POWER OPERATING AND AN ADDITIONAL 1000 MW POTENTIAL. BOTH PG&E AND SCE HAVE INTEREST IN SOLAR PHOTOVOLTAIC PRODUCTION TECHNOLOGIES, AND SCE HAS A 2 MW UNIT INSTALLED. ANOTHER SOLAR TECHNOLOGY, THE 10 MW DOE "SOLAR ONE" ELECTRIC PRODUCTION FACILITY, WILL BEGIN OPERATION IN 1982. SOUTHERN CALIFORNIA EDISON AND OTHERS ARE PLANNING A 5 MW SOLAR POND AT THE SALTON SEA BY 1984.

PROGRESS IN WIND APPLICATIONS HAS BEEN TRULY PHENOMENAL--SCE HAS A 3 MW WIND TURBINE IN OPERATION NOW AND HAS SIGNED LETTERS OF INTENTION FOR 25 MW MORE. PG&E HAS ORDERED A 2.5 MW BOEING TURBINE FOR SITING IN 1982 AND IS WORKING WITH WINDFARMS LTD. TO DEVELOP A 350 MW FARM ON LAND PG&E ACQUIRED EXPRESSLY FOR ITS WIND RESOURCE CHARACTERISTICS. TWO OTHER PRIVATE COMPANIES, US WINDPOWER AND FAYETTE MANUFACTURING, HAVE BOTH RECEIVED CONSTRUCTION PERMITS FOR 10 MW DEVELOPMENTS AND ARE NEGOTIATING PURCHASE CONTRACTS WITH PG&E AT THIS TIME.

THE GROWING UTILITY COMMITMENT TO INNOVATIVE TECHNOLOGIES IS DEMONSTRATED NOT ONLY BY THESE OPERATING FACILITIES BUT BY THEIR CONTINUING SUPPORT FOR RESEARCH AND DEVELOPMENT IN KEY AREAS, SPENDING OVER ANNUALLY ON R&D. PARTICULARLY PREMIUM PROJECTS PRESENTLY UNDERWAY INCLUDE SCE AND PG&E'S COMMITTMENTS TO EACH PROVIDE 30% OF THE OPERATING COSTS FOR THE PHASED DEVELOPMENT OF A SILICON RIBBON PHOTOVOLTAIC FABRICATION FACILITY UNDER CONSTRUCTION BY WESTINGHOUSE ELECTRIC CORPORATION. THE INITIAL CAPACITY FROM THIS FACILITY IS EXPECTED TO BE ABOUT 477 KW, AND IF THE PROJECT IS SUCCESSFUL, PRODUCTION LEVELS WILL BE INCREASED TO 25 MW/YEAR. THE SACRAMENTO MUNICIPAL UTILITY DISTRICT IS ALSO PURSUING SOLAR CELL TECHNOLOGY WITH A 100 MW PROPOSAL FOR WHICH IT IS SEEKING FEDERAL SUPPORT.

WATERSHED GEOTHERMAL TECHNOLOGY DEVELOPMENT IS ALSO UNDERWAY, WITH EPRI AND SAN DIEGO GAS AND ELECTRIC CO. (SDG&E) RECENTLY SIGNING A PARTICIPATION AGREEMENT TO PROCEED WITH THE DESIGN AND CONSTRUCTION OF A 50 MW BINARY-CYCLE GEOTHERMAL DEMONSTRATION POWER PLANT, TO BE COFUNDED BY EPRI, DOE, AND A GROUP OF SOUTHERN CALIFORNIA UTILITIES. CONSTRUCTION IS SCHEDULED FOR COMPLETION IN 1984. THE PURPOSE OF THE PROJECT IS TO DEMONSTRATE THE COMMERCIAL VIABILITY OF BINARY-CYCLE TECHNOLOGY AS A WAY TO DEVELOP NATURAL HOT WATER RESOURCES OF MODERATE TEMPERATURE AND SALINITY, WITH COMMERCIAL AVAILABILITY PROJECTED FOR 1986.

EPRI IS ALSO INVOLVED WITH SOUTHERN CALIFORNIA EDISON IN A STATE-OF-THE-ART, 100 MW COAL GASIFICATION/COMBINED CYCLE DEMONSTRATION PROJECT. WITH THE PARTICIPATION OF BECHTEL POWER CO., GENERAL ELECTRIC, TEXACO, EPRI AND SCE, $150 MILLION OF $300 MILLION TOTAL PROJECT COST HAS BEEN COMMITTED. (NEGOTIATIONS ARE UNDERWAY WITH PG&E, DOE AND AN OVERSEAS CONSORTIUM FOR FURTHER FUNDING.) INITIATION OF CONSTRUCTION IS SET FOR JULY, 1981. EPRI'S $50 MILLION CONTRIBUTION REPRESENTS THE LARGEST FINANCIAL COMMITMENT EPRI HAS EVER MADE TO A SINGLE PROJECT.

THE UTILITY COMMITMENTS I'VE REVIEWED HAVE OF COURSE BEEN FURTHERED BY CALIFORNIA'S EXTREMELY STRONG LEGISLATIVE COMMITMENT TO THE INNOVATIVE AND RENEWABLE TECHNOLOGIES. WE FOR EXAMPLE, ARE PRESENTLY IMPLEMENTING AN $80 MILLION WIND ENERGY DEVELOPMENT PROGRAM AND HAVE FUNDED EXTENSIVE BIOMASS, SMALL HYDRO, COGENERATION, METHANOL AND OTHER RESOURCE EVALUATION AND R&D EFFORTS.

ALTHOUGH THE SCALE IS CERTAINLY MODEST, GIVEN THE FIXED CONSTRAINT OF HAVING TO BALANCE THE BUDGET EVERY YEAR, THERE ARE PRESENTLY SEVERAL STATE PROGRAMS AVAILABLE TO PROVIDE FINANCIAL ASSISTANCE FOR ALTERNATIVE ELECTRIC GENERATION RESEARCH AND DEVELOPMENT. THE CALIFORNIA ALTERNATIVE ENERGY SOURCE FINANCING AUTHORITY, TO BEGIN OPERATION IN 1981, MAY ISSUE UP TO $200 MILLION IN BONDS TO ASSIST SOLAR, BIOMASS, WIND, GEOTHERMAL, SMALL HYDROELECTRIC, AND OTHER PROJECTS "WHICH WILL REDUCE THE USE OF FOSSIL AND NUCLEAR FUELS." ANOTHER RECENTLY ENACTED LAW ENABLES THE CALIFORNIA POLLUTION CONTROL FINANCING AUTHORITY TO ISSUE TAX-EXEMPT REVENUE BONDS TO FINANCE THE INSTALLATION OF "RENEWABLE ENERGY RESOURCE DEVICES": DEVICES THAT PRODUCE ELECTRICITY WITHOUT USING FOSSIL OR NUCLEAR FUEL. AN EARLIER LAW ESTABLISHED

A REVOLVING FUND FOR 20 BIOMASS DEMONSTRATION PROJECTS, INCLUDING COGENERATION. FINALLY, THE CALIFORNIA LEGISLATURE RECENTLY PASSED SEVERAL TAX INCENTIVES FOR ALTERNATIVE TECHNOLOGIES, INCLUDING ACCELERATED DEPRECIATION FOR COGENERATION AND ALTERNATIVE ENERGY EQUIPMENT AND TAX CREDITS FOR WIND TURBINES AND SOLAR PHOTOVOLTAIC CELLS. IN ADDITION TO OFFERING FINANCIAL ASSISTANCE TO ALTERNATIVE ENERGY TECHNOLOGIES, THE STATE LEGISLATURE HAS CREATED A $120 MILLION ENERGY AND RESOURCE FUND TO PROVIDE DIRECT FINANCING OF SPECIAL ALTERNATIVE ENERGY PROJECTS AND PROGRAMS, FINANCED OUT OF INCREASED REVENUES FROM OIL PRODUCTION ON STATE LANDS RESULTING FROM FEDERAL OIL PRICE DECONTROL.

WHILE NOT ALL OF THIS FUND GOES FOR ENERGY PROJECTS, OUR JUST APPROVED 81-82 STATE BUDGET INCLUDES $2 MILLION IN STATE MATCHING MONEY FOR SMUD'S 100 MW CENTRAL STATION PHOTOVOLTAIC INSTALLATION $250,000 FOR A SCE SOLAR POND FACILITY, AND OVER $1.5 MILLION FOR COGENERATION INVESTMENTS IN OUR UNIVERSITY FACILITIES.

VI. CONCLUDING THOUGHTS: THE IMPORTANCE OF A CONTINUING PARTNERSHIP

WHILE MY TESTIMONY HAS FOCUSED ON ACTIVITIES IN CALIFORNIA, I'D LIKE TO CONCLUDE WITH SOME THOUGHTS FROM A MORE NATIONAL PERSPECTIVE.

FIRST, I WOULD EMPHASIZE THAT, ALTHOUGH CALIFORNIA IS SURELY ONE OF THE STATES MOST ADVANCED IN IMPLEMENTING A UTILITY ENERGY SERVICE STRATEGY, THESE ACTIVITIES ARE BY NO MEANS LIMITED TO OUR COAST.

IN WIND FOR EXAMPLE, OVER 30 UTILITIES WERE INVOLVED IN DOE'S LARGE WIND TURBINE PROGRAM; SIX WILL BE INSTALLING ONE OR MORE LARGE WIND MACHINES, AND AN ADDITIONAL 24 ARE COLLECTING DATA IN ANTICIPATION OF INSTALLING SYSTEMS IN THE FUTURE. EIGHT OTHER UTILITIES ARE NOW INVOLVED IN INSTALLATION OF LARGE (100 KW OR LARGER) MACHINES, AND 49 UTILITIES ARE TESTING AND MONITORING SMALL WIND MACHINES.

UTILITIES AROUND THE COUNTRY HAVE DEMONSTRATION PROJECTS UNDERWAY OR PLANNED FOR SOLAR ELECTRIC, HOT-WATER GEOTHERMAL, PHOTOVOLTAICS, AND FUEL CELL ELECTRICITY PRODUCTION TECHNOLOGIES. EPRI REPORTS THAT THE NUMBER OF SOLAR THERMAL PROJECTS UNDERTAKEN BY UTILITIES HAS INCREASED BY 10% IN 1980, WHILE UTILITY PARTICIPATION IN PHOTOVOLTAICS CONTINUES TO GROW, WITH 47% INCREASE IN THE NUMBER OF REPORTED PROJECTS SINCE 1979.

IN BOSTON, BOSTON EDISON AND WHEELABARTOR-FRYE ARE JOINTLY FINANCING THE CONSTRUCTION OF A COGENERATION PLANT THAT WILL BURN SOLID WASTE. ALL OF THE ELECTRICITY AND STEAM FROM THIS PLANT WILL BE SOLD TO BOSTON EDISON, AND ADDITIONAL REVENUES WILL ARISE FROM SOLID WASTE DISPOSAL CHARGES. NEW YORK ALREADY HAS OPERATING OR UNDER CONSTRUCTION OVER 200 MW OF MUNICIPAL WASTE COMBUSTION FACILITIES. IN NORTH ANDOVER, MASSACHUSETTS, UNIVERSAL OIL HAS CONSTRUCTED A MAJOR INDUSTRIAL COGENERATION FACILITY THAT BURNS SOLID WASTE. THE OUTPUT OF THIS FACILITY IS APPROXIMATELY 30 MW AND NEES HAS CONTRACTED TO PURCHASE THE ENTIRE OUTPUT AT 90% AVOIDED COST. IN ADDITION, MASSACHUSETTS ELECTRIC, A MEMBER OF THE NEW ENGLAND ELECTRIC SYSTEM, HAS CONTRACTED TO BUY AT 90% AVOIDED COST A VARIABLE OUTPUT OF UP TO 27.5 MW FROM ARLINGTON MILLS POWER HOUSE, AN INDEPENDENT INDUSTRIAL ENERGY AND STEAM SUPPLIER UTILIZING COGENERATION FACILITIES. FLORIDA POWER AND LIGHT HAS CONTRACTS WITH TWO COGENERATORS, PURCHASING THE VARIABLE OUTPUT FROM 8-18 MW FROM A LOCAL SUGAR MILL, AND GENERATING ANOTHER 60 MW FROM WASTE STEAM FROM A SOLID WASTE BURNING PLANT OPEATED BY METROPOLITAN DADE COUNTY.

ON THE DEMAND SIDE OF COURSE UTILITIES IN ALL PARTS OF THE COUNTRY HAVE HAD LOAD MANAGEMENT PROGRAMS FOR SOMETIME, AND VIRTUALLY ALL STATES WILL BE ESTABLISHING RCS PROGRAMS. DOE HAS ALREADY APPROVED OVER 41 STATE PLANS AND 30 NON-REGULATED UTILITY PLANS.

THOUGH FINANCE PROGRAMS ARE NOT YET COMMONPLACE, NEARLY ALL UTILITY CUSTOMERS WILL BE OFFERED AT LEAST TECHNICAL ADVICE AND ASSISTANCE IN MAKING THEIR RESIDENCES MORE ENERGY-EFFICIENT.

THESE NATIONAL ACTIVITIES AS WELL AS OUR EXPERIENCES IN CALIFORNIA APTLY DEMONSTRATE A SECOND POINT, I WOULD EMPHASIZE IN CLOSING, WHICH IS THE ESSENTIAL NEED FOR A STRONG AND CONTINUING COMMITMENT TO PARTNERSHIP--BETWEEN GOVERNMENT AND THE PRIVATE SECTOR, AND AMONG LEVELS OF GOVERNMENTS--IN THE EVOLUTION OF THESE NEW UTILITY ROLES AND ACTIVITIES.

I REALIZE ITS NOT IN VOGUE TO BE AN ADVOCATE OF GOVERNMENT IN PRESENT TIMES, BUT THE PROGRESS TO DATE HAS VERY MUCH DEPENDED ON SUCH PARTNERSHIPS. THE FEDERAL GOVERNMENT, FOR EXAMPLE, HAS BEEN ABSOLUTLY CENTRAL IN SETTING THE BROAD POLICY CONTEXT THROUGH NECPA, PURPA, THE ESA AND OTHERS. THE STATES HAVE BEEN EQUALLY ESSENTIAL IN THEIR ROLE OF TRANSLATING BROAD FEDERAL CONSTRUCTS INTO WORKABLE, EQUITABLE PROGRAMS SUITED TO UNIQUE STATE NEEDS AND CIRCUMSTANCES.

ESPECIALLY CRUCIAL STATE RESPONSIBILITIES REMAIN TO BE MET IN THE COMING PERIOD: MONITORING, EVALUATION AND PROGRAM REDESIGN. IN CALIFORNIA, WE HAVE FOUND THAT A STRONG STATE ROLE IN DIRECT REGULATION IS ALSO AN IMPORTANT SUPPLIEMENT TO THE BROAD FEDERAL MANDATES. THIS WEEK, FOR EXAMPLE, WE WILL BE ADOPTING OUR SECOND GENERATION BUILDINGS STANDARD FOR NEW RESIDENTIAL CONSTRUCTION, WHICH WILL ASSURE OUR FUTURE HOUSING STOCK WILL USE ONLY A QUARTER OF THE ENERGY USED IN 1975-TYPE CONSTRUCTION. A STATE MANDATE FOR CONSERVATION RETROFIT OF THE INEFFICIENT EXISTING

HOUSING VERY NEARLY PASSED BOTH HOUSES OF OUR LEGISLATURE LAST SESSION, AND A SIMILAR BILL IS BEING CONSIDERED THIS YEAR.

LOCAL GOVERNMENTS IN OUR STATE HAVE ON OCCASION THEMSELVES TAKEN A STRONG LEAD IN ESTABLISHING LOCAL ENERGY EFFICIENCY REQUIREMENTS, AND HAVE ALSO BEEN SUCCESSFUL IN CREATING "MUNICIPAL SOLAR UTILITIES" TO ADVISE AND OFFER FINANCING TO CUSTOMERS INTERESTED IN SOLAR AND OTHER RENEWABLE RESOURCE APPLICATIONS.

OUR EXPERIENCE AS A REGULATORY COMMISSION HAS SHOWN US REPEATEDLY THAT LITTLE CAN BE ACCOMPLISHED WITHOUT A COOPERATIVE PARTNERSHIP WITH THE UTILITIES OR INDUSTRIES AFFECTED. THE MAGNITUDE OF THE R&D TASK IS GENERALLY BEYOND THE CAPABILITY OF ONE COMPANY OR UTILITY AND REQUIRES THE SUPPORT NOT ONLY OF THE UTI UTILITIES AND INDUSTRY, BUT OF CONGRESS AND THE DOE. TO SOME EXTENT, THESE VENTURES HAS BEEN SUCCESSFUL BECAUSE THE PRIVATE SECTOR PARTNERS THEMSELVES HAVE HAD FUNDAMENTAL COMMITMENT TO THE NEW SERVICE STRATEGIES AND TECHNOLOGIES.

THANK YOU FOR YOUR ATTENTION AND I HOPE YOU WILL FEEL FREE TO CALL UPON OUR STAFF IF YOU HAVE QUESTIONS ON THE ENERGY SERVICE CORPORATION REPORT, OR FOR ANY OTHER ASSISTANCE YOU MAY NEED. WE WILL BE RELEASING A FINAL COPY OF THAT REPORT IN LATE JULY, WHICH WE WILL FORWARD FOR YOUR REVIEW.

Mr. FUQUA. Thank you, Mr. Walker.

Mr. Hemphill, we have a bill on the floor and have to leave shortly, so could you summarize your statement? You do have a short statement so could you summarize it?

Mr. HEMPHILL. Let me simply do that and ask that it be inserted for the record.

Mr. FUQUA. Yes, it will be inserted.

Mr. HEMPHILL. Let me make several brief points for you this morning. I realize it's late in the time period here, but let me point out I am speaking from a background in the TVA where we have a number of things underway similar to what Jim Walker referred to in California.

Let me say I am not a financial expert, but it seems to me the issue you are considering here today expressed in direct and straightforward terms is that the utilities are not making enough money. At least that seems to be the general complaint. This is generally more elegantly expressed as a concern they are not therefore going to be able to build enough capacity, and as a result of this economic growth will be limited and possibly the lights will go out.

I think you would be wise to examine some of the assumptions which underlie these sorts of arguments. They seem to me to be fairly straightforward.

First of all, the assumptions are that economic growth demands electricity growth at a more rapid rate than in the economy, usually 1.2 to 2.2 times economic growth.

Second, costs are up dramatically.

Third, there is the assumption of what I would call the "monopoly mindset" that if as a power producer you are important enough to be granted a monopoly of production, there is no substitute for what you produce and people have to keep using it.

You put all those together and you get what many, although certainly not all, utilities would have you believe is the vision of the future, that they have to have more rate increases to build more capacity.

I question these assumptions. There is the TVA's own experience with its residential customers where we have reduced per capita consumption of our customers since 1977 at about 2.4 percent per year. It seems to me to prove it is possible there is substantial long-term elasticity of demand for electricity. In fact, this is an area where we have been more wrong as forecasters than in any other area, except possibly the price of oil, in the past. Economic growth may not demand growth in electricity consumption. In TVA we use a ratio of .6, not 1.2, in our forecasts.

And I think there are cheaper ways to make electricity than those centralized alternatives now proposed.

From that I would draw a couple of very quick conclusions.

First of all, with regard to the future of the electric utility industry, the growth in electric consumption is bound to be limited. We are making a product whose price is increasing faster than the inflation rate. Therefore, the thing that is logical and likely to happen is that our share of the market will diminish.

Second, electric production should be decentralized, small, and nonmonopolistic if it is to be efficient.

Third, the lights are not going to go out. I assure you General Electric will be delighted to sell any utility in the country packaged gas turbines which they can install very quickly. It will be expensive power, but the lights won't go out.

The conclusion I draw from this, based on experience and listening to more discussions like this than I would really have chosen to, is that anybody who endeavors to forecast for you future needs for capacity, and whose forecast does not specifically take account of conservation and other decentralized production resources, is either being naive or intentionally misleading. There are questions of cost and liability and consumer acceptance on some of these things, but I would suggest to you there are equally important questions of cost, reliability, and consumer acceptance for central power stations.

Finally, I think the solution generally proposed is something of a two-edged sword: If utilities aren't making enough money now, then they need to make more money. The way to make more money is to raise the prices. If they raise prices, people will use less, and that will decrease the need for more plants, and then they won't need more money.

As an associate of mine said, it is analogous to the solution for Chrysler's financial problems being to propose a raise in the price of its cars.

[The prepared statement of Mr. Hemphill follows:]

STATEMENT BY ROBERT F. HEMPHILL, JR.
DEPUTY MANAGER OF POWER, TENNESSEE VALLEY AUTHORITY
FOR SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS
HOUSE SCIENCE AND TECHNOLOGY COMMITTEE

JUNE 23, 1981

OVER THE PAST DECADE, THE ELECTRIC POWER INDUSTRY'S OPERATING ENVIRONMENT HAS CHANGED DRAMATICALLY. THE ONCE STEADY GROWTH IN ELECTRIC LOADS THE INDUSTRY MUST SERVE HAS SLACKENED. FUEL COSTS HAVE RISEN SHARPLY, FORCING ELECTRIC RATES UP AS POWER PRODUCERS PASS THE COSTS OF PRODUCING ELECTRICITY ALONG TO THEIR CUSTOMERS. CONSTRUCTION COSTS FOR BUILDING NEW PLANTS HAVE INCREASED BEYOND THE INDUSTRY'S EXPECTATIONS, AND CONSTRUCTION DELAYS HAVE MAGNIFIED THE INCREASES STILL FURTHER.

ANY ELECTRIC UTILITY EXECUTIVE, WHEN INVITED TO COMMENT PUBLICLY ON THE FUTURE OF HIS INDUSTRY, SHOULD FIRST HUMBLE HIMSELF PRIVATELY BY REVIEWING HOW ACCURATE SUCH PROGNOSTICATIONS HAVE BEEN IN THE PAST. THE ATTACHED CHART INDICATES HOW INACCURATE WE HAVE BEEN WHEN PREDICTING THE FUTURE. IT GRAPHICALLY ILLUSTRATES THE DIFFERENCE BETWEEN OUR ESTIMATE OF THE FUTURE IN 1974--ONLY SEVEN YEARS AGO--AND OUR CURRENT RANGE OF ESTIMATES. PLEASE NOTE THE DOTTED LINE ON THE CHART; I WILL EXPLAIN THAT IN A BIT MORE DETAIL SHORTLY.

THE MAJOR POINT TO BE MADE TODAY IS THAT CONSERVATION AND THE DECENTRALIZED GENERATION OF ELECTRICITY, MUCH OF IT BY NONUTILITY POWER PRODUCERS, WILL PLAY AN INCREASINGLY IMPORTANT ROLE IN THE FUTURE OF THE INDUSTRY.

GIVEN TODAY'S DIFFICULT FINANCIAL CONDITIONS, SOME ELECTRIC POWER PRODUCERS ARE ALREADY LOOKING BEYOND CONVENTIONAL MEANS OF SATISFYING CUSTOMERS' ENERGY REQUIREMENTS. CERTAINLY, CONVENTIONAL GENERATING PLANTS ARE STILL BEING BUILT, BUT POWER PRODUCERS INCREASINGLY ARE

TURNING TO CONSERVATION AND ALTERNATE ENERGY SOURCES AS A MEANS OF MEETING SOME OF THE PUBLIC'S FUTURE ENERGY NEEDS AT THE LOWEST POSSIBLE COST. FOR SOME POWER PRODUCERS, CONSERVATION PROVIDES IMMEDIATE SAVINGS THROUGH REDUCED OPERATION OF EXPENSIVE OIL-FIRED PLANTS. FOR OTHERS, CONSERVATION IS VIEWED AS A LONG-TERM OPTION WHICH DELAYS THE NEED FOR EXPENSIVE, FUTURE CAPACITY ADDITIONS. CONSUMERS INSTALLING CONSERVATION MEASURES BENEFIT FROM REDUCED UTILITY BILLS WHILE MAINTAINING A HIGH LEVEL OF COMFORT. CONSERVATION IN THE FORM OF ENERGY EFFICIENCY REQUIRES CAPITAL INVESTMENTS, NOT PHYSICAL SACRIFICE.

PACIFIC GAS AND ELECTRIC, SOUTHERN CALIFORNIA EDISON, PACIFIC POWER AND LIGHT, PENNSYLVANIA POWER AND LIGHT, NEW ENGLAND ELECTRIC, AND ARKANSAS POWER AND LIGHT ARE AMONG THOSE WHO HAVE MADE SERIOUS EFFORTS IN THIS DIRECTION, AND IT IS INTERESTING TO NOTE THAT YOU WILL HAVE REPRESENTATIVES FROM SEVERAL OF THESE UTILITIES TESTIFY TOMORROW.

AT TVA, WE HAVE COMMITTED OURSELVES TO A COMPREHENSIVE CONSERVATION PROGRAM INVOLVING RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL CUSTOMERS. IT IS THE CHEAPEST CAPACITY THAT WE CAN BUY. OVER THE LONG TERM, WE EXPECT TO REDUCE THE NEED FOR INVESTMENT IN ADDITIONAL GENERATING CAPACITY, WITH SAVINGS THAT FAR EXCEED THE PROGRAM'S COSTS.

THE CHART REFERRED TO EARLIER HAS EXPLICITLY REPRESENTED THE CAPACITY SAVINGS WE CURRENTLY EXPECT FROM OUR CONSERVATION PROGRAMS: 2,716 MW IN 1990 FROM OUR RESIDENTIAL PROGRAMS AND 858 MW FROM OUR COMMERCIAL AND INDUSTRIAL PROGRAMS, FOR A TOTAL OF 3,574 MW, THE EQUIVALENT OF MORE THAN THREE NUCLEAR UNITS. THESE SAVINGS, OF COURSE, ARE NOT WITHOUT COST; OUR ESTIMATES OF THE COST OF THESE PROGRAMS TO TVA THROUGH 1990 IS $600 MILLION. BUT WE FEEL THAT THIS COMPARES QUITE FAVORABLY WITH THE COST OF BUILDING NEW CAPACITY--$2,000-$3,000/KW.

THE CONSERVATION PROGRAM ALSO PROVIDES IMMEDIATE SAVINGS TO PARTICIPATING CUSTOMERS. THIS IS PARTICULARLY TRUE IN THE AREA SERVED BY TVA BECAUSE OUR CUSTOMERS USE ABOUT TWICE THE NATIONAL AVERAGE AMOUNT OF ELECTRICITY PER CUSTOMER. TVA'S ENERGY CONSERVATION PROGRAM THUS PROVIDES BENEFITS TO PARTICIPATING CUSTOMERS, TO THE POWER SYSTEM, AND ULTIMATELY TO THE RATEPAYERS IN GENERAL.

THESE ARE TANGIBLE BENEFITS WHICH RECOMMEND THEMSELVES TO ALL POWER SYSTEMS IN THE COUNTRY THAT FACE THE PROBLEM OF MEETING INCREASED DEMANDS IN TODAY'S INFLATIONARY ECONOMIC CLIMATE. AS A PIONEER IN THIS AREA, TVA HAS HAD THE OPPORTUNITY NOT ONLY TO BREAK NEW GROUND BUT ALSO TO LEARN IMPORTANT LESSONS IN HOW SUCH PROGRAMS CAN BE MOST EFFICIENTLY ESTABLISHED AND OPERATED.

A COMPLETE SUMMARY OF OUR CONSERVATION, SOLAR, AND LOAD MANAGEMENT PROGRAMS IS ATTACHED. I WOULD ALSO LIKE TO OUTLINE A FEW OF THE MORE VALUABLE LESSONS WE HAVE LEARNED IN THE MANAGEMENT OF THESE PROGRAMS. THOSE LESSONS INCLUDE THE FOLLOWING POINTS:

-- FINANCIAL INCENTIVES ARE NECESSARY IF CONSERVATION AND SOLAR PROGRAMS ARE TO ACHIEVE THEIR FULL POTENTIAL IN REDUCING DEMAND AND DEFERRING THE NEED FOR ADDITIONAL CAPACITY. THE SUCCESS OF TVA'S HOME INSULATION PROGRAM IS LARGELY DEPENDENT ON THE AVAILABILITY OF NO-INTEREST OR SUBSIDIZED LOANS. HOME ENERGY AUDITS ARE USELESS UNLESS CONSUMERS IMPLEMENT RECOMMENDED ENERGY CONSERVATION MEASURES. RECENTLY ANALYZED DATA FROM OUR CUSTOMERS REVEALS THAT ONLY 35 PERCENT OF THOSE CONSUMERS WHO HAVE INSTALLED

CONSERVATION MEASURES IN THE LAST TWO YEARS HAVE APPLIED FOR THE TAX CREDIT OR PLAN TO DO SO. THIS UNDERLINES THE IMPORTANCE OF FRONT-END FINANCING.

-- LOW-INCOME FAMILIES--THOSE WITH INCOMES BELOW $5,000--REPRESENT ONE-FIFTH OF THE TVA AREA'S POPULATION, YET ONLY 4 PERCENT HAVE HAD HOME ENERGY SURVEYS PERFORMED. SEVENTEEN PERCENT OF FAMILIES WITH INCOMES GREATER THAN $25,000, BY CONTRAST, HAVE HAD A SURVEY. A SPECIAL EFFORT IS NOW BEING MADE TO REACH LOW-INCOME FAMILIES, WHO OFTEN BEAR THE BRUNT OF THE PERSONAL SACRIFICES REQUIRED BY RISING ELECTRIC RATES.

-- FAMILIARITY WITH APPLICABLE BUILDING SAFETY CODES AND COOPERATION WITH LOCAL OFFICIALS ARE ESSENTIAL. IN TVA'S MEMPHIS SOLAR WATER HEATING PROGRAM, FOR EXAMPLE, PLUMBING CODE INSPECTORS RAISED QUESTIONS ABOUT THE DESIGN OF THE HEAT EXCHANGERS THAT SHOULD HAVE BEEN RESOLVED BEFORE THE PROGRAM BEGAN. WE EVENTUALLY HAD TO REPLACE THE EXCHANGERS IN 180 WATER HEATERS AS A RESULT.

-- QUALITY CONTROL IN EQUIPMENT MANUFACTURING AND INSTALLATION IS EQUALLY VITAL TO THE SUCCESS OF SOLAR AND CONSERVATION PROGRAMS. ALL TVA-SPONSORED INSTALLATIONS MUST PASS AN INSPECTION AFTER THE EQUIPMENT IS PUT IN. ABOUT 20 PERCENT OF ALL INSTALLATIONS FAIL THE INITIAL INSPECTION. UNFAMILIARITY WITH CONSERVATION AND SOLAR TECHNOLOGY AND LOW LABOR QUALITY SEEM TO BE LARGELY RESPONSIBLE FOR THIS HIGH FAILURE RATE. CONTRACTORS WHO CONSISTENTLY FAIL TO MEET TVA'S STANDARDS ARE DROPPED FROM THE PROGRAM.

-- Concern for safety has been neglected in much wood heater technology. Of more than 1,000 wood heaters on the market today, only 150 meet the requirements for TVA's Wood Heater Program. The TVA program makes wood heater safety a key concern, ranking equally with performance.

-- Power producers should attempt to work with the conservation and solar industry, not compete with it. For example, TVA initially set out to design solar homes itself. Due to our lack of experience in the home-building field, the homes could have been improved with regard to function, attractiveness, location, and price. We plan in the future to work with homebuilders and realtors, those who best know how to build and sell homes. TVA will provide the technical expertise to maximize the use and effectiveness of solar energy. We have discovered that, in order to sell, a solar house must primarily be a desirable home. While important to TVA, solar features are a secondary consideration from the point of view of the marketplace.

-- Reliable data collection is important in keeping track of a program's progress and cost-effectiveness and it does not occur automatically. The time to plan this phase of the effort is before the program starts. The evaluation plan should be sufficiently detailed to allow management to measure results of each element of the program on a regular basis.

-- PROMOTING DECENTRALIZED ENERGY IS A REAL MANAGEMENT CHALLENGE, REQUIRING A WELL-THOUGHT-OUT AND TIGHTLY RUN ADMINISTRATIVE STRUCTURE. UNLIKE THE CENTRALIZED AND HIGHLY STRUCTURED TASK OF BUILDING A NEW POWER PLANT, THESE PROGRAMS INVOLVE KEEPING TRACK OF AND EFFECTIVELY USING SMALL AMOUNTS OF LABOR, MONEY, AND MATERIALS IN THOUSANDS OF GEOGRAPHICALLY DISPERSED LOCATIONS.

-- CONSERVATION AND SOLAR PROGRAMS ALSO PRESENT A SIGNIFICANT MARKETING CHALLENGE. IN TRYING TO CONVINCE THOUSANDS OF PEOPLE TO INSULATE THEIR ATTICS, WEATHERSTRIP THEIR DOORS, AND INSTALL SOLAR WATER HEATERS OR WOOD HEATERS, A POWER PRODUCER IS COMPETING FOR DISCRETIONARY CONSUMER DOLLARS. IN EFFECT, IT IS SELLING ENERGY CONSERVATION, AND THE TASK MUST BE APPROACHED WITH THE SAME KIND OF FERVOR THAT WENT INTO SELLING KILOWATTHOURS FOR SO MANY YEARS UNTIL CHANGING ECONOMICS MADE THAT APPROACH OBSOLETE.

THAT CONCLUDES MY STATEMENT; I WILL BE HAPPY TO ANSWER ANY QUESTIONS YOU MAY HAVE.

# # #

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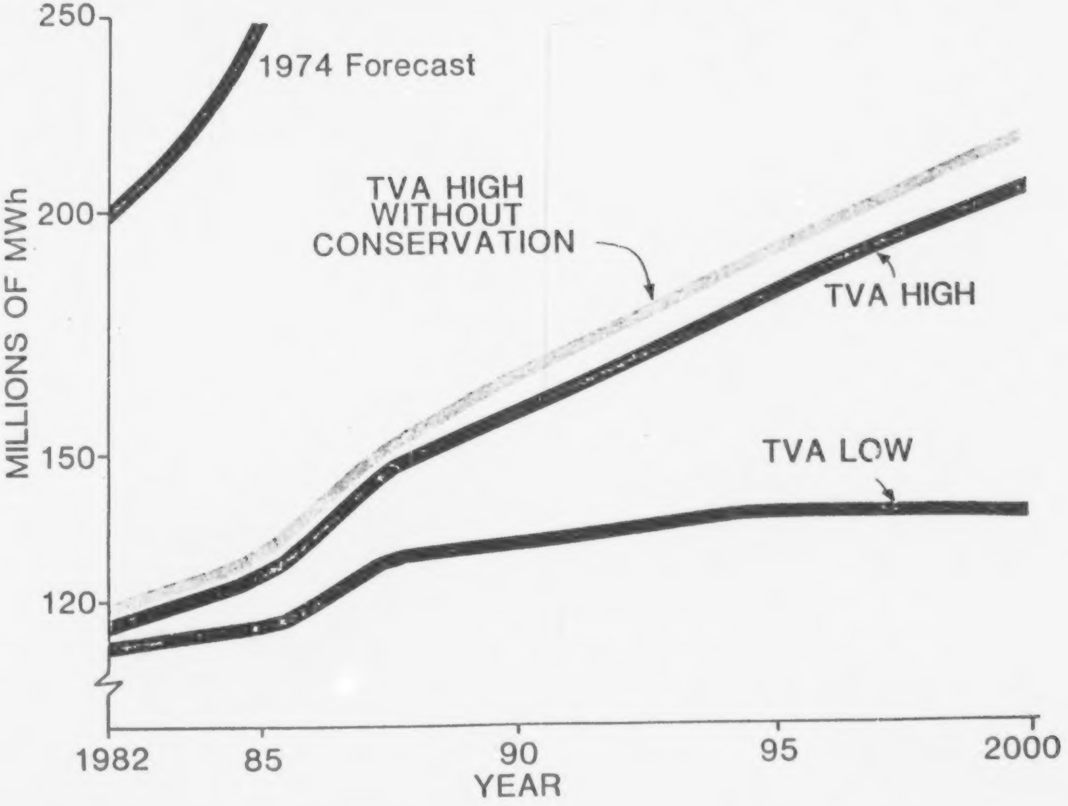

TVA

Tennessee
Valley
Authority

Office of Power
Division of Energy Conservation
and Rates

Program Summary

APRIL 1981

THE TENNESSEE VALLEY AUTHORITY

The Tennessee Valley Authority is a corporate agency of the United States Government, created by Congress in 1933 to develop the Tennessee River system and other natural resources of the Tennessee Valley and adjoining areas. TVA serves an area covering approximately 80,000 square miles, including Tennessee and parts of Alabama, Mississippi, Kentucky, Georgia, North Carolina, and Virginia.

During the early years, the agency constructed a system of dams to harness the Tennessee River for flood control, navigation, and power generation. TVA also developed a national fertilizer development center, and helped initiate reforestation and forest management practices.

The demand for TVA power grew rapidly in the decades following the 30's. TVA generating facilities were expanded to include coal-fired, combustion turbine, and nuclear generating plants which, combined with TVA's hydro plants, now have a projected FY 1981 generating capacity of 31,108 megawatts.

TVA provides electricity to 2.7 million consumers by selling wholesale power to 160 municipal and cooperative distributors of TVA power in the Tennessee Valley; TVA also directly serves 57 very large industrial customers and Federal installations. During FY 1981 TVA total electric sales to consumers is expected to be 115.8 billion kilowatthours.

The rapid growth in demand for electricity slowed in the early 1970's during the economic recession that followed the 1973 Arab oil embargo. At the same time, rising energy costs created new attitudes about the use of energy, and conservation began to play an important role in reducing demand growth.

The effective, efficient use of energy has become more and more important to TVA and to consumers of TVA power because, as costs have increased, the economic benefits of energy conservation have increased. In reponse, TVA has initiated energy conservation programs that could save $9 billion by 1990 by eliminating the need for four or five new TVA generating units. This savings would represent a demand reduction of 3,574 megawatts and a reduction in consumption of 7,287 million kWh.

These programs, aimed at eliminating energy waste, are designed to help consumers hold their overall energy use to the amount that is actually needed.

TVA's conservation effort, formulated by the Division of Energy Conservation and Rates, is implemented in the field through TVA's Division of Energy Use and Distributor Relations' network of seven district offices located throughout the Valley. District personnel work directly with the distributors of TVA power and their employees to inform Valley consumers of the benefits of conservation and seek their participation in specific TVA and power distributor conservation projects.

For additional information about the availability of TVA's energy conservation programs in your area write or call one of the seven TVA District Offices listed below:

In West Tennessee:

TVA Western District
P.O. Box 999
Jackson, Tennessee 38301

(901) 668-0915

John F. Phillips, Manager

In Middle Tennessee:

TVA Central District Office
1719 West End Building
Nashville, Tennessee 37203

(615) 329-2424

G. Glen Burgess, Manager

In Northeast Tennessee, North Carolina, Virginia:

TVA Appalachian District Office
200 Brookvale II Building
Knoxville, Tennessee 37902

(615) 632-6750

Vaughn B. Hickman, Manager

In Southeast Tennessee and Northwest Georgia:

TVA Southeastern District Office
1709 South Lee Highway
Cleveland, Tennessee 37311

(615) 478-1141 Bradley County
(615) 755-0061 Hamilton County and
other areas

G. Douglas Carver, Manager

In Northern Alabama:

TVA Alabama District Office
501 First Federal Building
Muscle Shoals, Alabama 35660

(205) 386-2431

Richard B. Davis, Manager

In Central and Northern Mississippi:

TVA Mississippi District Office
P.O. Box 470
Tupelo, Mississippi 38801

(601) 842-5825

John C. Hall, Manager

In Southern Kentucky:

TVA Kentucky District Office
P.O. Box 1088
Hopkinsville, Kentucky 42240

(502) 885-4357

John L. Smith, Manager

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INTRODUCTION

This document is a summary of the programs currently being conducted by the Tennessee Valley Authority and distributors of TVA power in the areas of energy conservation, solar and renewable energy, and load management. The programs benefit TVA as well as consumers, and are designed to:

- Save money for the power system by reducing the short-run demand for high-cost peak power, and, over the long run, defer or eliminate the need to add expensive new central generating stations to the TVA power system.
- Provide a means of rapidly reducing electrical demand in the event of emergencies such as power plant failures.
- Provide actual field data on efficiencies, costs, and customer acceptance of various technologies from which to forecast the long-range electrical needs of the Valley.
- Meet legal requirements such as those of the National Energy Conservation Policy Act of 1978.

Much of our experience may be helpful to other electric utilities, as well as to those with a general interest in decentralized energy alternatives. Costs, benefits, and the feasiblity of specific programs, of course, will vary from one electric system to another.

A contact is usually listed following each program described in the summary to provide information on program design. General information can be obtained from:

Deputy Manager of Energy Use, Office of Power	Robert F. Hemphill, Jr. (615) 755-3287
Director, Division of Energy Conservation and Rates	Robert C. Steffy, Jr. (615) 755-2061
Chief, Conservation and Energy Management Branch	Eddie L. Tramel (615) 755-3651
Chief, Solar Applications Branch	Patricia H. Harris (615) 755-6741
Chief, Load Management Branch	John W. Sanders, Jr. (615) 755-3591
Chief, Planning and Communications Staff	Thomas W. Swanson (615) 755-8677
Director, Division of Energy Use and Distributor Relations	Richard C. Crawford (615) 755-2321

CONSERVATION AND ENERGY MANAGEMENT BRANCH

HOME INSULATION PROGRAM

Program Overview

The 2.5 million Tennessee Valley residential consumers use 33 percent of TVA's generated kilowatthours. In calendar year 1980, the average annual TVA residential energy use was 15,437 kilowatthours, almost twice the national average. Much of this consumption is for electric heat: 46 percent of TVA consumers have electric heat, compared to 16 percent nationally.

TVA residential rates, while lower than the national average, have nonetheless increased 175 percent between 1970 and 1980. The most widely used rate of the 12 residential rates available to distributors of TVA power, as of April 1981, is 3.8 cents per kilowatthour for the first 500 kilowatthours each month, and 4.2 cents per kilowatthour for all additional usage. Consumers with electric space heating averaged 19,320 kilowatthours in fiscal year 1980, which will cost approximately $780 under the current rate schedule. Existing homes in the TVA power service area, moreover, are not well insulated. Average effective attic insulation is R-6; 15 percent of all homes do not have any attic insulation.

TVA's Home Insulation Program (HIP) was initiated in August 1977 and has been expanded several times since then. Conducted in cooperation with the distributors of TVA power, the program provides onsite inspections of residential dwellings and no-interest loans to finance weatherization measures. The program goal is to weatherize over 580,000 homes by 1990. The program is expected to account for an annual energy saving of 2.6 billion kilowatthours by 1990. By that time the HIP will also produce a consumer benefit of $109 million a year at today's rates and will save about 1,150 megawatts of peak demand for the TVA power system, at a total estimated program cost of $230 million.

Program Features

- Energy Surveys and Recommendations

  Regardless of the type of fuel used in heating or cooling a home, all residential consumers are eligible for the free home energy survey upon request. The onsite inspection is conducted by TVA-trained energy advisors to determine the insulation or weatherization levels of the attic, floor, ductwork, water heater, windows, doors, and other areas of the home. When the inspection is completed, the energy advisor recommends improvements where needed, their potential savings, and the estimated cost of these improvements. The energy advisor also discusses certain conservation practices with the consumer, such as proper thermostat setting. The energy advisor informs the consumer of the availability of no-interest loans for weatherization measures and provides a list of local contractors who have agreed to meet TVA standards for the quality of the insulation materials and their correct installation. Tenants, landlords, and mobile home residents are also eligible for the free survey and recommendations.

- No-Interest Loans for Weatherization Measures

  In electrically heated or cooled homes, the consumer may use the interest-free loan for material and labor costs for attic and floor insulation, storm windows, insulated doors, caulking, water heater insulation, and weatherstripping. The loan will cover the cost of the materials if the consumer wants to do the work himself rather than hire a contractor.

  The maximum loan amount is $2,000; consumer loans now average $1,200. Repayment is made in equal payments on the consumer's electric bill for a period of up to seven years.

- Inspection

  When weatherization is completed, the energy advisor inspects the work to make sure it meets TVA's installation specifications. Weatherization work installed with no-interest financing must pass this inspection before payment is made to the contractor. Consumers not using program financing may request and receive an inspection at no cost. On the average, 30 percent of the jobs have failed this inspection.

Resources

- All of the 160 distributors of TVA power are participating in HIP. The cooperation of the power distributors is essential to the program's operation and success, as the distributors receive survey requests, frequently provide office workspace for the energy advisors, handle billing and loan payments, and often hire energy advisors to supplement the TVA field force.

- There are currently about 1,500 contractors participating in the program. To be listed as a participating contractor, a firm must agree to comply with TVA's standards for insulation materials and their installation. A contractor may be delisted for, among other things, repeated failure to meet TVA installation standards; failure to remedy defects in material or workmanship to satisfy TVA standards; failure to remedy damages to a consumer's property resulting from the installation of weatherization measures; or providing false information to TVA or a consumer.

Status

As of March 1981:

- 335,338 homes had been surveyed.
- 161,336 consumers had received loans for 297,444 weatherization measures.
- Approximately $135 million had been loaned to consumers.

Program Cost and Benefits

- The total cost of HIP through 1990 is $230 million.
- The program is expected to save 2.6 billion kilowatthours annually by 1990 and defer the need for 1,150 megawatts of new capacity.
- An independent evaluation by ICF, Inc., of Washington, DC., of the impacts of the initial program indicated that the use of electricity for residential heating was significantly reduced with the installation of attic insulation, the only weatherization measure covered under the initial HIP. Consumption was reduced by an average of 2,200 kilowatthours or 20 percent. The use of electricity for air conditioning was reduced by an average of 530 kilowatthours or 15 percent. In simple payback terms, the average $310 investment for attic insulation should be recovered within four years in reduced electric bills. In terms of energy use, the evaluation showed a combined energy savings of 50.5 million kilowatthours annually, based on the installation of attic insulation alone, for the first 27,000 participants in the program.

Information Contact

A. B. Coleman
Tennessee Valley Authority
Power Service Center-6
Chattanooga, Tennessee 37401
Telephone: (615) 755-3656

HEAT PUMP FINANCING PROGRAM

Program Overview

The electric heat pump is a heating and cooling system that functions like an air-conditioning unit, but takes about half as much electricity to heat a home in the TVA power service area as central electric resistance heat.

To help residential consumers save on energy costs and to encourage the adoption of this energy-efficient heating system, TVA developed the Heat Pump Financing Program (HPFP) as an adjunct to its Home Insulation Program. The financing provision, offered through participating power distributors, provides qualifying consumers low-interest loans for the purchase and installation of the units.

Based on a fully insulated 1,500-square-foot home, TVA estimates that a consumer can save from 4,000 to 7,000 kilowatthours during a single heating season with an electric heat pump. Compared to conventional electric heating and cooling, a heat pump can save $168 to $294 a year on electric heat bills. It is expected that over 60,000 loans will be made through 1990.

Low-interest loans for ground water heat pumps are also available under the HPFP, if the water source meets quality and quantity tests. Ground water systems operate much like air source heat pumps, except they transfer heat into a home by taking it from water instead of air.

Program Features

o Energy Surveys and Recommendations

To participate in this program, owners of single-family dwellings or duplexes first obtain a free home energy survey offered by TVA and the distributors. If a heat pump loan is to be made, the consumer is also required to carry out the cost-effective weatherization measures recommended in the survey.

Following the home energy survey, a trained heat pump advisor will help the consumer decide if a heat pump system will be cost-effective for the home. The heat pump advisor will furnish the consumer with a list of participating heat pump dealers who have agreed to install the heat pump system according to TVA specifications.

- Low-Interest Loans for Heat Pump Purchase and Installation

  Consumers may borrow money at low interest for buying and installing the electric heat pump. Both air-source and water-source heat pumps are included in the program. The interest rate for the HPFP loan (10.5 percent) reflects TVA's estimated cost of borrowing money. Consumers have up to 10 years to repay the loan in equal payments on their electric bills.

  The loans average $3,100 per installation. The cost depends on the size of the unit, the amount of ductwork needed, and the cost of labor.

- Inspection

  When the installation work is completed by a heat pump dealer, the heat pump advisor inspects the work to make sure that it meets TVA installation standards. Dealer payment is not made until the installation passes this inspection.

Resources

- 123 of the 160 power distributors are participating in the HPFP; this covers 84.2 percent of all residential consumers.

- Forty-five TVA and 25 distributor heat pump advisors are conducting heat pump surveys and inspections.

- There are 650 heat pump dealers or installers participating in the program.

Status

As of March 1981:

- 16,351 heat pump recommendations had been completed.
- 7,709 installations had been made, with a total amount loaned of $24 million.

Program Cost and Benefits

- The HPFP will cost TVA $17.4 million through 1990.

- The program is expected to save 274 million kWh annually by 1990 and defer the need for 45 MW of new capacity.

- Total consumer benefits will be $11.5 million annually by 1990, at today's rates.

Information Contact

R. Lee Culpepper
Tennessee Valley Authority
Power Service Center-4
Chattanooga, Tennessee 37401
Telephone: (615) 755-8981

COMMERCIAL AND INDUSTRIAL CONSERVATION AND ENERGY MANAGEMENT PROGRAM

Program Overview

More than half of all TVA power is used by the commercial and industrial (C&I) sector. In fiscal year 1980 this represented 77.9 billion kilowatthours consumed by approximately 299,750 distributor-served consumers and 49 directly-served consumers.

Many of the distributor-served consumers lack the technical expertise to reduce their energy consumption. The directly-served consumers often have competent engineering staffs, but they are frequently delayed in implementing conservation projects because of competing demands for capital. To overcome these obstacles, the C&I Conservation and Energy Management Program offers energy management surveys at TVA's cost and low-interest financing to help consumers eliminate energy waste. Analyses of energy use and identification of energy conservation opportunities (ECOs) are performed and reported to the consumer. In addition, engineers assess the potential for cogeneration, solar energy, and the use of other renewable resources. The surveys are conducted primarily by enginners, with engineering aides collecting data and performing the less complicated surveys. The program will benefit TVA by reducing peak power requirements and delaying the need for future generating capacity.

The program goals are to reduce peak demand by 543 megawatts and annual energy use by 957 million kilowatthours by 1990.

Program Features

- Energy Management Survey

  A walk-through survey is available, at no cost, to all TVA C&I consumers whose facilities can be analyzed for energy conservation potential in approximately an eight-hour period. If the TVA engineer determines that the energy-consuming systems in the consumer's facility are too complex or the facility is too large to be evaluated in one day, a free estimate of the cost for a more comprehensive energy management survey will be prepared. The consumer will pay the cost incurred by TVA in performing the comprehensive survey. However, the survey charge will be refunded to the consumer who implements ECOs, with paybacks of seven years or less, which achieve a minimum of 75 percent of the estimated dollar savings possible if all recommended ECOs are implemented.

- Financial Assistance

  To ensure that energy conservation measures are implemented without delay, TVA will loan a minimum of $1,000 and a maximum of $100,000 to qualifying C&I consumers. The loans are extended only for ECOs aimed at saving electricity.

  Profit-making consumers are eligible for loans to implement ECOs with a payback period of greater than 3 years, provided that they first privately finance and implement ECOs with a payback period of 3 years or less. Non-profit consumers are eligible for loans regardless of the payback period. Loans carry an interest rate equal to TVA's estimated cost of borrowing money (10.5 percent for FY 81), plus 1 percent to cover administrative costs. Loans are repaid in equal monthly installments. The length of time for repayment is based on the ECO payback period, up to a maximum of 10 years. There is no penalty for early or accelerated repayment.

Resources

- As of March 1981, 158 TVA engineers and engineering aides were conducting energy management surveys.

Status

As of March 1981:

- 3,892 surveys had been made, covering 123.5 million square feet of space.
- 23 loans had been made for a total of $164,000.
- 426.2 million kilowatthours annually saved if the recommended ECOs are taken.
- 157.7 thousand kilowatts demand reduction if the recommended ECOs are taken.

Program Cost and Benefits

- The program is estimated to cost $145 million through 1990.

- By 1990 the program will reduce peak demand by 543 megawatts and lower annual energy use by 957 million kilowatthours.

Information Contact

Phillip D. Lawson
Tennessee Valley Authority
Power Service Center-5
Chattanooga, Tennessee 37401
Telephone: (615) 755-3841

LOW-INCOME INITIATIVES

Of the 2.4 million households in the TVA service area, one third, or 787,600, have an annual income of less than $8,000 (the approximate poverty level for a family of four). However, analysis of the characteristics of the participants in TVA's Home Insulation Program indicates that the low-income groups who are hurt most by rising energy costs are not being effectively reached. For example, 97 percent of the persons receiving Home Insulation Program surveys were non-Hispanic whites; 47 percent worked as professionals, proprietors, or managers; and 94 percent were homeowners residing in single-family living quarters. Because of the serious impact electric rate increases can have on the low-income consumers, TVA has initiated several efforts to assist low- and fixed-income persons in reducing their energy costs. These efforts include the targeting of conservation programs and low-income communities as well as cooperative efforts with Federal, State, and local agencies concerned with helping the poor.

Specific Programs

- TVA Support for the DOE Low-Income Weatherization Program

  TVA is currently doing two things to help maximize the effectiveness of the Department of Energy (DOE) low-income weatherization program that is operated through the designated State offices and administered by local Community Action Agencies (CAAs). First, TVA energy advisors have been assigned to each CAA on a priority basis to provide the CAAs with energy audits and inspections of completed work. These audits and inspections take precedence over all other work. Second, TVA is providing some training and technical assistance to CAA personnel in the proper installation of weatherization measures in this program.

  As of March 1981: 25 advisors had been assigned; 16,465 single-family dwellings had been weatherized; and 500 CETA workers had been trained in home weatherization. Because of its success, this program is being implemented in all seven states served by distributors of TVA power.

- Public Housing Initiative

  There are 30,000 electrically heated public housing units in the TVA service area. A program to weatherize all of these units over a two-year period has been undertaken. The Atlanta Regional Housing and Urban Development (HUD) office requested and received a blanket waiver of the general HUD prohibition against the borrowing of money by local housing authorities. Lifting this restriction permitted all public housing authorities to participate in TVA's Home Insulation Program. DOE funds will be used where low-income requirements are met. TVA no-interest loans made under the Home Insulation Program will be used where there are insufficient DOE funds or when Public Housing Authorities do not meet DOE's grant criteria. As of March 1981, 5,857 public housing units had been surveyed and 1,075 insulated.

- Privately-Owned Rental Initiatives

  Sixty to seventy percent of low- to moderate-income persons are renters, and, in general, they pay their own utility bills. Owners thus have little incentive to invest in conservation since they will receive none of the direct benefits of lower bills. And tenants, especially low-income tenants, are unlikely to invest in property they do not own. To deal with this problem, TVA has initiated a special effort to increase the rental market participation in HIP. TVA has concentrated on the major cities in its power service area and held a series of meetings and discussions with owners in the cities to explain the benefits of weatherization retrofit measures, from both the tenant's and the apartment owner's perspectives. A special HIP brochure and other promotional materials have been designed to help penetrate this market. Preliminary results indicate rental property owners are responding: TVA has already performed energy surveys on more than 5,400 privately owned rental units in this fiscal year. TVA is also providing window stickers to those apartment owners who implement the suggested weatherization measures, thereby increasing the marketability of these units by showing prospective tenants that they are energy efficient. As of March 1981, 46,057 rental units has been surveyed.

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ENERGY SAVER HOME PROGRAM

Program Overview and Features

TVA's Energy Saver Home Program encourages the design and construction of energy-efficient new homes. A total of 30,000 to 40,000 new homes are built annually in the TVA service area. Many of these homes are not constructed to optimum energy-efficient standards, resulting in increased demands on the power system and higher energy costs for consumers.

In 1975 TVA initiated a voluntary program called the Super Saver Home Program that encouraged consumers to build homes to TVA-recommended standards. The program has resulted in approximately three percent of the new homes being built to the standards. To expand this impact, TVA considered several approaches.

Both a mandatory building standard as a condition of electric service and a hook-up charge on all new energy inefficient buildings have been considered and rejected. In deciding against these approaches, the TVA Board determined that TVA will develop an expanded voluntary program to promote energy-efficient standards for new homes and apartments. This will be done in conjunction with participating power distributors, home builder associations, home builders, local and Federal government agencies, lending institutions, real estate agencies, and appraisers. To promote the program, TVA will:

- Develop and maintain cost-effective, energy-efficient standards known as "Energy Saver" standards for new homes and small apartments. These standards will allow design flexibility and give consideration to solar features.
- Encourage existing local government building inspection departments to inspect participating construction in their jurisdiction for compliance with the TVA standards. An Energy Saver Home medallion will be awarded to homes that meet these standards.
- Assist in the sales promotion of residential buildings built to the Energy Saver standards.
- Encourage lenders, appraisers, and realtors to consider favorably appraisal and loan qualification advantages a purchaser obtains when he buys an Energy Saver Home.
- Encourage home builder associations to adopt voluntarily specific goals for the construction of Energy Saver Homes as a percentage of all homes built by their members.

Status

The mechanics, format, and materials for the Energy Saver program will be released first to participants to inform them of the specifics of the program and then to the general home-buying public in the summer of 1981.

Benefits

Homes built to Energy Saver standards can reduce space heating costs by up to 70 percent and cooling costs by up to 33 percent, compared to homes built to the most widely used building standard and equipped with a central electric furnace and air-conditioning. This would result in an annual saving of 8,750 kWh or $369 to the consumer. Solar and other energy-saving construction techniques could make further reductions.

If 30,000 homes a year were built to these standards, the energy saving to TVA would be over 234 million kilowatthours per year.

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SOLAR APPLICATIONS BRANCH

MEMPHIS SOLAR WATER HEATER DEMONSTRATION PROJECT

Program Overview

Seventy-seven percent of all residential consumers in the Tennessee Valley use an electric water heater, which represents 20 percent of the average annual electric consumption of the typical residential user. The Memphis Solar Water Heater project, TVA's first major solar program, began in October 1978 to demonstrate the practicality of heating water for residential use with a renewable energy resource. The program included the design, installation, and low-interest financing of 1,000 solar water heaters which supplemented existing electric resistance water heating systems.

The project was also designed to encourage small businesses in support of TVA's regional development objectives. The project has resulted in the establishment of independent installers, suppliers, and a warehousing operation.

Program Features

- TVA surveyed the home of each interested consumer to determine the feasibility of installing a solar water heater.
- Participants receive 20-year loans with an interest rate of 3.37 percent to pay for the solar systems and their installation. Financing is provided by TVA, with no down payment required. Loans are repaid through electric bills at the rate of $13 per month. Twelve dollars of the monthly payment is for the solar system itself; the remaining $1 is for routine maintenance. The Memphis Light, Gas and Water Division collects the monthly payments through electric bills.
- To ensure quality performance, the TVA-designed systems, which include storage and backup heating timed only to operate off-peak, are installed by crews that have completed TVA-accredited training courses. Once the system is in place, the installation is given a comprehensive inspection by a TVA quality assurance inspector. Payment is made to the contractor only after the system passes inspection.

Resources

- New Memphis Development Corporation (NMDC), a nonprofit community development corporation, assisted in the administration of the project. The NMDC operates a solar resource center that purchases, stores, and delivers solar equipment and operates a training program for local contractors who want to install solar systems under TVA's program.
- Six advisors, one quality assurance inspector, and one coordinator conduct the solar surveys and inspections.
- The systems are being installed by six small businesses, including Sunbelt Solar, Inc., a subsidiary of the NMDC.

Status

- As of March 1981, TVA had received 4,634 requests for audits, 1,000 contracts had been signed, and 966 systems had been installed and passed inspection.

Program Cost and Benefits

- The total cost of a system is $2,000 plus sales tax. Consumers purchasing systems are eligible for a Federal energy tax credit. The systems are estimated to deliver up to 65 percent of the homeowner's annual water heating.
- The Memphis project will benefit the TVA power system by supplying the equivalent of 2.8 million kilowatthours per year per 1,000 systems installed. This figure translates into a life-cycle savings of 56 million kilowatthours per 1,000 systems installed. The systems should also provide winter peak reduction of 1.3 megawatts.
- Total project cost is estimated to be approximately $5 million, with $2 million of this amount repaid by consumers purchasing the systems and $1.2 million provided by appropriated funds. Thus, the net cost to TVA will be approximately $1.8 million.

Expanded Program

In January 1981, TVA expanded the Memphis Solar Water Heater project, modeling this expansion after Solar Nashville/Solar Middle Tennessee. The expansion, which extends the project through June 1983, provides consumer financing at TVA's estimated cost of money (10.5 percent in fiscal year 1981) for a term of 20 years. Like the original program, the expanded program is being conducted in cooperation with Memphis Light, Gas and Water Division and provides free surveys of consumers' homes and post-installation inspections of systems. Under the expansion, consumers select any system from a list of approved systems and installation contractors from a list of TVA-trained contractors.

As of March 1981, TVA had received 648 requests for audits, 10 contracts had been signed, and 2 systems had been installed and inspected.

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NASHVILLE/MIDDLE TENNESSEE SOLAR WATER HEATER DEMONSTRATION PROJECT

Program Overview

The Nashville/Middle Tennessee Solar Water Heater Demonstration Project was approved by the TVA Board in August 1979 as the second stage of TVA's solar water heating program. The Nashville area was chosen because a market analysis showed that, next to Memphis, Nashville has the largest number of:

- Electric water heater installations (129,000)
- New home starts (3,500 per year)
- People between the ages of 25 and 49 (259,000)
- Families earning $25,000 or more annually (53,000)
- High school and college graduates (125,000)

National research indicates that all these factors positively influence the market potential for solar systems.

Undertaken in cooperation with the Nashville Electric Service (NES), Murfreesboro Electric Department (MED), Lebanon Electric Department (LED), and Middle Tennessee Electric Membership Corporation (MTEMC), the goal of the program is to install 11,000 domestic solar water heaters by December 1983.

Program Features

- Advisors from TVA or participating TVA power distributors survey the homes of interested customers to determine the feasibility of installing a solar water heater.
- Customers are offered a choice of systems and a selection of qualified installation service companies. Manufacturers of the solar systems are required to allow their systems to be independently tested to meet TVA's performance criteria before their systems can be included on the list of TVA-approved suppliers and be eligible for financing to homeowners. Once an installation is completed, the system is inspected by a TVA quality assurance inspector before payment is made to the installer.

- TVA and local banks, offering TVA guaranteed loans of up to $3,400, provide 20-year loans to consumers with an interest rate of 10.5 percent. Systems priced between $2,600 and $3,800 are available to consumers.
- The participating power distributors collect monthly loan payments through electric bills.

Status

- As of March 1981, 3,743 requests for audits had been received, 694 contracts had been signed, and 497 systems had been installed and passed inspection.
- Sixteen installers and 14 solar water heater systems had been approved.

Program Costs and Benefits

- Total project cost for both Nashville and Middle Tennessee is estimated to be $38.25 million, with $25.3 million to be repaid by consumers purchasing the systems. The 11,000 systems will provide energy savings of about 33 million kilowatthours per year and winter peak reduction of about 12.3 megawatts.
- Consumers will realize savings both directly through an estimated reduction of up to 80 percent in annual electricity use for water heating, and indirectly, through more stable rates reflecting TVA's reduced operating costs.

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WOOD HEATER PROGRAM

Program Overview

Forests cover more than half of the land in the Tennessee Valley, and wood residues alone could be a major source of energy if practical ways are found to put this resource to work. For this reason, TVA, in cooperation with 28 participating power distributors, is offering interest-free loans to consumers for the purchase and installation of 6,000 wood heaters. The distributor areas encompass 65 counties in all seven Valley States. Preliminary data indicates that wood heaters can provide a potential reduction of 50 percent or more in the amount of electricity used for home heating.

Program Features

- Interested consumers must first obtain a free home energy survey and insulate their attics to a minimum of R-19.
- Participants must select a heater that meets TVA requirements for safety and efficiency and must have a fire extinguisher and smoke detector. After installation, TVA inspects the heater, stovepipe, and chimney to ensure the safety of the system before payment is made to the contractor.
- Consumers receive interest-free loans of up to $800 to cover the cost of purchasing and installing an airtight, freestanding wood heater or fireplace insert. Local power distributors collect loan payments through monthly electric bills. Loans are repaid in equal installments over a period of five years.

Resources

- Forty-nine energy advisors perform surveys for both the Wood Heater and Home Insulation Programs.

Status

- As of March 1981, 4,995 surveys had been conducted, 4,237 agreements had been signed, and 2,724 wood heaters had been installed and inspected.

Program Cost and Benefits

- The total cost of the program is projected to be $5.3 million with $3.6 million in the form of loans to be repaid to TVA.
- The 6,000 installed wood heaters will displace an estimated 15 megawatts of installed capacity.

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SOLAR HOMES FOR THE VALLEY

Program Overview

This program includes designing, constructing, and monitoring the performance of passive solar homes. The homes are passive--constructed to take maximum advantage of the sun without using mechanical equipment for collecting or storing solar energy. The project should allow cost comparisons of various passive technologies.

Program Features

- Eleven different houses were designed by TVA's Architectural Design Branch. Thirty-five homes, including at least two and as many as five examples of each design, are being built across the Valley to determine how the houses perform in different climates.
- The designs take advantage of such factors as the angle of the sun at various times of the year, the siting of the house on the lot, the vegetation surrounding the house, the shape of the house, and the construction materials. Features such as Trombe walls, greenhouses, direct gain, and mass walls are used to absorb the sun's heat and distribute it throughout the house after sundown. Summer cooling is achieved through the use of roof overhangs, landscaping, and window shape and placement to encourage natural ventilation.
- Consumers who buy the homes receive a payment of $2,500 for allowing TVA to install monitoring equipment (to compare predicted and actual energy performance) and use the homes for limited demonstration purposes during their first year of occupancy.
- The homes vary in size from 1,000 to 2,000 square feet, and will sell for approximately $33,000 to $71,500 (including the cost of the lot).
- An additional nine homes will be built in Knoxville, Chattanoga, and Huntsville. TVA will work with nine builders to incorporate passive solar features into designs previously built by the selected builders. The homes will be designed to reduce summer and winter peak electricity demands as compared to conventional homes under construction. TVA will monitor the modified versions of the homes as well as the previously built versions. This will allow TVA to determine the impact of the design modifications on total energy consumption and load profile. The Home Builders Associations in each of the targeted cities will sponsor these homes.

Resources

- Six non-profit community development organizations familiar with local conditions are acting as sponsors and are coordinating construction with nine builders.
- Construction of the homes is supervised by the Solar Applications Branch. The Architectural Design Branch is responsible for field inspections to certify that the homes conform to TVA specifications.

Status

- As of March 1981, construction was completed on 34 houses and nearing completion on the last of the 35 TVA-designed homes.
- Two homes have been sold.
- Construction on nine builder-designed homes is expected to begin during the summer of 1981.

Program Cost and Benefits

- Total cost to complete the current program is estimated to be $4.7 million. Of this amount, $1.83 million is in the form of loans to be repaid to TVA.
- Each house is expected to save from 2,500 kWh to 7,000 kWh of electricity annually for heating and cooling as compared to a typical home now built in the Valley.

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SOLAR MODULAR HOMES PROJECT

Program Overview

Through assistance to modular home manufacturers and prospective buyers, this program will demonstrate the effectiveness of modular homes that are designed to include solar components. A total of 130 of these homes will be located throughout the Valley to determine design performance in all climatic regions. Modular homes, which are manufactured and trucked to a site where they are permanently emplaced, offer a reasonably-priced alternative to those Tennessee Valley families who cannot afford site-built homes. The mean family income in the Tennessee Valley is only 80 percent of the national average.

Program Features

- Approximately 20 new passive modular solar home designs are being developed by five modular house manufacturers with TVA financial and design assistance.
- From these designs, 130 prototypes will be manufactured and sited. Twenty units will receive extensive performance monitoring.
- The monitored homes are expected to be sited and put in place by the summer of 1982.

Status

- As of March 1981, ten of the twenty final designs had been approved and the remaining ten designs were being reviewed.
- Eleven homes have been manufactured; three are in place.
- Two homes have been sold with a third pending contract approval.
- Two manufacturers are now producing modular homes. Others are expected to be in production by July 1981.

Program Cost and Benefits

- Total project cost is $2,993,000.
- The total winter peak reduction to TVA will be approximately 5.3 kW per house, and the energy savings will be approximately 8,700 kWh annually per house or about 261,000 kWh over the 30-year life of the homes.

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SOLAR PROJECTS IN TVA FACILITIES

Program Overview

TVA now owns or leases 718 facilities, with space used for the production of power, offices, laboratories, warehouses, and recreation. A total of 63 solar projects at these facilities are now in the planning and implementation process. This inventory of TVA buildings has the potential to support 150 solar water heating systems, 150 active solar space heating systems, 125 passive solar space heating systems, and 20 passive solar cooling systems.

The objective of this program is to reduce nonrenewable energy use by replacing electric and fossil fuel sources with renewable energy sources in these facilities. Solar projects are implemented when they are determined to be cost-effective by a life-cycle analysis required under the Federal Energy Management and Planning Program. Cost-effective solar projects are financed by TVA along with Federal funding (when available) through the Department of Energy (DOE).

Program Features

- Energy audits of all TVA buildings are being conducted and energy conservation and solar energy opportunities are being developed, evaluated, and implemented.
- Eleven solar projects have been approved for funding through the Solar in Federal Buildings Demonstration Program, a DOE program designed to stimulate growth of the solar industry. DOE has also provided funds for 23 photovoltaic projects through the Federal Photovoltaic Utilization Program, a program designed to accelerate development of a commercially viable photovoltaic industry.

Status

- As of March 1981, a total of 63 solar systems had been authorized for TVA buildings. These include 20 domestic hot water (DHW) systems; 4 active space heating systems; 8 passive solar systems; 2 industrial process heat systems; 3 solar cooling systems; 25 photovoltaic systems; and 1 wind generator.
- Thirty-five energy audits have been performed on TVA buildings.

Program Cost and Benefits

- The budget for the TVA Facilities Solar Project is $3.2 million over the next three years. DOE has provided $1.2 million of these funds.

- The projects currently authorized should save TVA 28 million kWh on an annual basis once they are in full operation.

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COMMERCIAL AND INDUSTRIAL SOLAR WATER HEATING

Program Overview

The program is designed to demonstrate and analyze the impacts of commercial solar hot water systems for participating customers, the TVA power system and the power distributors. Through incentive payments TVA will support the installation of solar water heating systems in 23 commercial establishments. Eighteen of the systems will be small commercial systems and five will be large commercial systems.

Program Features

- Seven categories of large hot water users (food stores, eating and drinking establishments, hotels, and other lodging places, firms engaged in personal services, health services, educational services, and multi-unit housing) will be targeted for installation of either large-capacity (greater than 500 gallons of hot water per day) or small-capacity (500 gallons per day or less) solar water heating systems.
- At least one large system will be located in each of the five major population centers in the Valley, with the remaining systems to be dispersed throughout the seven TVA districts.
- C&I sector consumers will contract privately for the design and installation of systems, with TVA providing partial funding and design review. TVA will perform monitoring before and after the system is installed to determine sizing and performance of all systems.

Status

- The Commercial Water Heating project authorization was approved by the TVA Board of Directors on December 18, 1980. As of March 1981, seven sites have been identified, one design has been started and one contract has been signed.

Project Cost

Total cost to TVA of this two-year demonstration program is $1,427,567: $1,200,567 from Power funds and $227,000 in appropriated funds.

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COMMERCIAL AND INDUSTRIAL PASSIVE SOLAR BUILDINGS PROGRAM

Program Overview

There are about 93,000 commercial buildings in the TVA service area and about 2,000 new commercial buildings are constructed each year. TVA has adopted an approach to ensure that these buildings use solar energy wherever possible. Some of the solar applications which may be employed by commercial and industrial customers include greenhouse additions, Trombe walls, and the use of direct gain through large south-facing windows for heat absorption and retention. These types of solar applications and others can easily be included in the design of new buildings, and many are feasible as retrofit projects for older structures.

Program Features

- Solar-conscious architectural and engineering design assistance is given to owners, investors, building designers, and contractors of commercial and industrial property. Building types receiving assistance included schools, senior citizen centers, day-care centers, churches, multi-purpose centers, town halls, retail establishments, multi-unit housing projects, and airport facilities.
- Design guidelines are being developed which, in contrast to the case-by-case approach of the design assistance program, will offer assistance on a generic building-type basis. These guidelines will be developed for 20 different building categories and will include energy-related design criteria which will be incorporated into the normal design process.

Status

As of March 1981, 174 requests have been received from the commercial and industrial sector. Of these, 109 have been given technical assistance or were determined to be ineligible for assistance.

Program Costs and Benefits

The project funding for fiscal year 1981 is $774,000.

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COMMERCIAL AND INDUSTRIAL BIOMASS PROGRAM

Program Overview

To promote the use of wood in commerce and industry, TVA has initiated a program of information and education for industry officials in decision-making roles and architect/engineers who design the heating systems and industrial boilers used in the region. Use of wood in commercial and industrial applications has substantial potential to benefit the power system by reducing the peak-load demand and by providing cogenerated electricity to the grid. It can also stimulate the Valley economy by diverting money now spent on imported fuels to locally produced fuels, which will result in additional employment. The use of wood and other biomass fuels should be attractive to Valley firms, once it is adequately demonstrated, since this technology offers payback periods ranging from two to five years.

Program Features

- Technical assistance is made available to selected firms considering conversion to biomass fuels.
- Limited financial incentives may be offered to encourage demonstrations of innovative applications and to allow the monitoring of actual installations to determine the full impact on the power system and the environment.
- During fiscal year 1981, 35 feasibility studies will be performed resulting in 15 system designs which, in turn, will lead to 8 demonstration projects.

Status

As of March 1981, 87 potential sites have been identified and 32 of these have been screened. Twelve feasibility studies and two designs have been completed.

Program Costs and Benefits

The project funding for fiscal year 1981 is $904,000 from Power funds to be used for electric replacement and cogeneration and $1.2 million in appropriated funds.

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LOAD MANAGEMENT BRANCH

AIR-CONDITIONING CYCLING PROGRAM

Program Overview

The TVA system has as much as a 9,000 megawatt swing between early morning and late afternoon demand on hot summer days. The Air-Conditioning Cycling Program will allow TVA to level its summer demand peak, and reduce the need to operate expensive oil-fired generators, by installing a remote-controlled switch on the existing central air conditioners or heat pumps of 50,000 volunteer consumers. The participants receive a monthly credit on their summer electric bills, and, in return, will allow TVA to cycle the normal operation of their air-conditioning systems.

Program Features

o When the demand on the TVA power system reaches a predetermined level, the compressors, but not the fans, of central air conditioners of participating customers are turned off by a radio-activated remote control switch for approximately 7 minutes per half-hour. Because the off-cycle is short, consumers should experience little, if any, inconvenience.

o TVA will bear all costs of the program, including those of buying, installing, maintaining, and inspecting the remote-control equipment. Participating consumers are given a $5-per-month credit on their electric bills during the months of June through September.

o Participants must agree to participate in the program for one air-conditioning season. Thereafter, the agreement will be automatically renewed for one-year periods unless either party decides to cancel.

o Following the successful acceptance of the initial 50,000 units, TVA hopes to expand the program eventually to include 350,000 volunteers.

Resources

o Thirteen participating power distributors will enlist the initial 50,000 consumers and administer the monthly incentive payments.

o Energy advisors trained in load management techniques will complete contracts with consumers and inspect completed installations.

Status

- As of March 1981, there were 7,370 consumers enrolled in the program with 869 receivers installed. All of the initial 50,000 volunteers should be participating in the program by 1983.

Program Cost and Benefits

- TVA estimates the cost of the program to be approximately $7.7 million.
- Each installation will reduce TVA's summer peak demand by approximately 1.4 kilowatts, resulting in a total reduction of 68 megawatts at the time of the system peak.

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WATER HEATER CYCLING PROGRAM

Program Overview

TVA will install a remote-controlled switch on the electric water heaters of 50,000 volunteer consumers. The participants receive a monthly credit on their electric bills and, in return, will allow TVA to cycle the operation of their water heaters. The program allows TVA to make more efficient use of the generating equipment on the system and reduce the overall cost of generating electricity.

Program Features

- During peak periods, electricity for electric water heaters may be cut off for a period of up to four hours. Since water is a good heat storage medium, the interruption should not adversely affect the family's hot water supply.
- TVA energy advisors evaulate the interested family's hot water needs and the size of the water heater. The consumer is then advised as to whether he can participate in the program and still have enough hot water during periods when the power to the water heater has been turned off.
- TVA will bear all costs of the program, including those of buying, installing, maintaining, and inspecting the remote control equipment. Participating consumers are given a $2-per-month credit on their electric bills year round.
- Participants must agree to take part in the program for one full year. Thereafter, the agreement will be automatically renewed for one-year periods unless either party decides to cancel.

Resources

- The remote-controlled switches that TVA purchased for the Air-Conditioning Cycling Program can also be used in the Water Heating Cycling Program. Thus, the participating power distributors are the same, and TVA will encourage consumers to sign up for both programs for purposes of economy.
- Twelve participating power distributors will enlist 50,000 consumers and administer the monthly incentive payments.
- Load management energy advisors evaluate water heater size and advise consumers regarding participation. The advisors will complete contracts with consumers and inspect installations.

Status

- The Water Heater Cycling Program received TVA Board approval in July 1980. As of March 1981, there were 279 consumers enrolled in the program with 21 receivers installed. All of the initial 50,000 volunteers should be participating in the program by 1983.

Program Cost and Benefits

- TVA estimates the cost of the program to be approximately $6.5 million.
- Each installation will reduce TVA's winter peak by approximately 1.3 kilowatts and the summer peak by approximately .56 kilowatts, resulting in total reduction of 65 megawatts and 28 megawatts, respectively.

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OTHER PROGRAMS

Thermal Storage Field Test

The Thermal Storage Field Test will examine the practicality and benefits of using off-peak heat storage systems in Valley residences. Three different types of heat storage material will be tested: ceramic brick, pressurized water, and sodium sulphate, an eutectic salt which melts and solidifies at 85 to 90 degrees. All of the units use electricity during off-peak hours to produce and store heat in the storage material; then, during on-peak hours, heat is taken from the material to warm the home.

Eight power distributors are participating in the test: Athens Utilities Board, Sweetwater Board of Public Utilities, Columbus Light and Water Department, Alcorn Electric Power Association, Memphis Light, Gas and Water Division, Cumberland Electric Membership Corporation, Joe Wheeler Electric Membership Corporation, and Russellville Electric Board.

Sixty-five homeowners will be selected to participate in the three-year test. All participants will be billed under a special rate which charges less for electricity used during off-peak hours and more for electricity used during on-peak hours. Because these devices are designed essentially to function off-peak, participants can expect lower heating bills.

The test received Board approval on August 30, 1979. As of March 1981, 61 units had been installed. Estimated program cost is $600,000. Preliminary studies indicate a potential savings of six kilowatts per installation at the time of the system peak.

Additional information may be obtained from Hal Womble, Project & Program Implementation Section, (615) 755-3591.

Energy Use Display Meter Test

TVA is conducting a one-year test to determine whether consumers use less electricity when their homes are equipped with meters that give a dollars-and-cents display of the accumulating electric bill. Approximately 200 volunteer participants will receive the display meters and energy conservation literature. A control group of about 200 consumers will receive only the conservation material.

Some of the participants receiving the meters will be placed on a time-of-day rate schedule, and may also be given the opportunity to use the meter's appliance cycling option. Both of these features will allow the participants to concentrate their use of electricity during periods of the day when they will be billed less per kilowatthour.

The test received TVA Board approval in October 1979. Participating power distributors include Chickasaw Electric Cooperative, Sand Mountain Electric Cooperative, Glasgow Electric Power Board, Pontotoc Electric Power Association, Bristol Utilities Board, and Tishomingo County Electric Power Association. As of March 1981, 163 installations had been completed. The remainder are scheduled to be completed by June 1981. Cost of the program is estimated at $446,000.

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Programmable Thermostat Field Test

TVA is conducting a one-year field test of programmable or "Smart" thermostats in conjunction with Tri-State Electric Membership Corporation and West Kentucky Rural Electric Cooperative Corporation. The purpose of this test is to determine the usefulness of programmable thermostats in helping consumers shift heating/cooling load off-peak when given the incentive of time-of-day rates. The study will also assess the effects on TVA's system peak when the device is used as recommended by the manufacturers; i.e., as a nighttime set-back thermostat.

Twenty-four thermostats have been installed in each distributor's service area. Twelve consumers in each area are being billed on an experimental time-of-day rate and encouraged to use the device for load management purposes. Twelve consumers in each area are being billed under their standard rate and encouraged to use the device as a nighttime set-back thermostat. A control group will also be selected for comparison in each area.

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Commercial and Industrial Heat and Cool Storage Demonstration

The Commercial and Industrial Heat and Cool Storage Demonstration project will demonstrate the benefits of using either off-peak heat storage systems, off-peak cool storage systems, or a combination of both in conjunction with a time-of-day rate throughout the Valley. Eighteen demonstration projects will be conducted using consumers ranging in demand from less than 50 kW to 5,000 kW.

Twelve heat storage units will be tested: six using ceramic brick and six using water as the heat storage medium. The six remaining storage units will use ice as the storage medium.

All of these units use electricity during off-peak hours to produce and store heat or ice; then, during on-peak hours, the stored heat or cooling material is taken from the storage units to condition the area.

The test received Board approval on December 18, 1980. As of March 1981, sites had been selected for the installation of two heating units and one cooling unit. Estimated program cost is $833,000.

Additional information may be obtained from Hal Womble, Project & Program Implementation Section, (615) 755-3591.

DISPERSED POWER PRODUCTION

DISPERSED POWER PRODUCTION PROGRAM

Program Overview

To expand cogeneration in the TVA power service area, the TVA Board has adopted a dispersed power production policy as an extension of the Experimental Cogeneration Program initiated in August 1979. The Dispersed Power Production Program, developed in accordance with Section 210 of the Public Utilities Regulatory Policies Act of 1978, provides a market for electric energy produced by the region's cogeneration and small power production facilities, along with attractive standby power charges to cogenerators and technical assistance to potential cogenerators.

Program Features

- Producers have the option of either using the output of their production facilities to supply their own requirements, or selling their surplus or entire output to the connecting electric system, either the local distributor of TVA power or TVA.
- Power purchased by the utility will be paid for each month in accordance with the following price schedule:
  - For capacity less than 100 kW, without time-of-day metering capability, a price per kWh equal to 100 percent of the TVA wholesale monthly demand and energy charges. As of April 2, 1981, this price was 3.052 ¢/kWh.
  - For all other capacity, a price per kWh equal to 135 percent of the TVA wholesale monthly demand and energy charges during on-peak hours, 4.120 ¢/kWh as of April 2, 1981, and 85 percent of those charges during off-peak hours, or 2.594 ¢/kWh.
  - There will be no demand ratchet or special minimum charge for producers' power use.
- Producers may, at their option, reduce their operating risk by contracting for emergency and maintenance standby power. Consumers electing standby power in any amount, however, are subject to:
  - A reservation charge of 30 percent of the demand charge per month per kilowatt of the standby contract demand plus four percent of the demand charge per month per kilowatt of the consumer's total production capacity.

- A demand use charge of 20 percent of the demand charge per week per kilowatt of billing demand for maintenance standby power and 40 percent of the demand charge per week per kilowatt of billing demand for emergency standby power.

- An energy use charge of three percent per day per kilowatt of billing demand for standby power.

- The demand charge cited above is $6.05/kW as of April 2, 1981.

o The program provides some assurance that private investments in qualifying facilities can be recovered, since agreements for dispersed power production may continue in effect for a maximum of 10 years and agreements are renewable under succeeding programs. Moreover, TVA provides technical assistance to potential producers and distributors in arranging interconnection, but producers will bear the cost of system protection and parallelling equipment. There are no program requirements for dispatchability, minimum sales, or minimum size.

Status

o The program becomes effective after April 20, 1981. Cogeneration contracts have been signed with three large industrial plants under the Dispersed Power Production Program. These plants are now producing and supplying 6,625 kW of electricity to the TVA power system.

Information Contacts

Cogeneration and Distributor-owned Production:

Shelley M. Bostick
Tennessee Valley Authority
470 401 Building
Chattanooga, Tennessee 37401

Telephone (615) 755-6781

Windpower, Biomass, Photovoltaic Power Production:

Robert C. Cole
Tennessee Valley Authority
320 Credit Union Building
Chattanooga, Tennessee 37401
Telephone (615) 755-3621

Rates and Charges:

Ernest F. Seagle
Tennessee Valley Authority
604 Power Building
Chattanooga, Tennessee 37401

Telephone (615) 755-3531

Small Hydro Power Production:

James W. Swanson
Tennessee Valley Authority
Hydraulic Laboratory
Norris, Tennessee 37828
Telephone (615) 632-4460

Mr. **Fuqua**. Thank you.

I have less of a question than an observation. You and some of the other witnesses have said that we overestimated our supply needs. If we made such a colossal error on the original forecast, why does that not mean we are making one now when we have reduced our demand figures considerably?

Mr. Hemphill assured us the lights aren't going out, but is there the potential we could be making an error in underestimating our demand?

Mr. **Walker**. There is always that possibility. I think you have to recognize two factors, however. One is that we have a lot better information than we did when we were making those previous projections. In the old days for electricity forecasting, it was a straightedge and log paper and just projecting it out. Since then we have had 3 years successively where we have had utilities develop over 50,000 residential surveys, questionnaires. The data base is much bigger than it ever was before.

Second, with California, at least, the objective of displacing up to 80 percent of the oil used means we have given utilities additional justification to build power plants. Now we are simply saying, "We think the demand may be only growing 1.5 percent a year; but we want you to build power plants at a 2.5-percent-a-year rate because we want you to get off oil as soon as possible."

Mr. **Fuqua**. Isn't there cogeneration in oil in California?

Mr. **Walker**. But a lot of that is already being burned. That has already been burned, with no cogeneration, 80,000 barrels a day worth.

Mr. **Fuqua**. One of the questions that comes up and I think has been a theme of this is whether or not we should continue large central station power generation.

Now, TVA—don't you have three nuclear power plants in construction now, and you have a conservation and a solar program in operation? Is that a conflict?

Mr. **Hemphill**. It depends very much on your projections of the demand. What we have, in fact, done with our program—we have not authorized any new nuclear units since 1974 and we have, in fact, deferred four nuclear units, and the additional demand that we see above this capacity will be met by precisely the conservation and solar programs outlined here.

There is some theoretical conflict but we think we have about the right balance.

Mr. **Fuqua**. Mr. Curtis, what is your feeling about the large central power station of the future?

Mr. **Curtis**. Mr. Chairman, as you fully appreciate, I know, this country is very diverse. All sections of the country do not have the same requirements for the same potential to take advantage of the economies of scale of central generation of power.

Mr. **Fuqua**. If we could in my State take some of those power plants people are leaving in the Northeast and move them to Florida, it might help solve some of our problems.

Mr. **Curtis**. Yes, sir, I'm sure that would be advantageous. I'm sure there would still exist a considerable public benefit, need, and advantage in replacing existing oil-fired facilities with coal-fired centralization generation.

Mr. FUQUA. You are from a part of the country that predominantly uses oil.

Mr. CURTIS. Yes; I think that opportunity should be taken advantage of. And it can be better taken advantage of in a financing context that does not have to rely on project financing; it can be best taken advantage of where the purchasing or constructing entity can roll the risk of high technology applications into a bigger base.

May I throw out one thing in terms of response to what I would call your earlier caution?

Mr. FUQUA. Certainly.

Mr. CURTIS. I think it is entirely true that you can forecast incorrectly on the low side as well as forecast incorrectly on the high side. Your tendency to do so may be somewhat influenced, if you were a corporate manager, by the certainty that if you were to build additional capacity you would, by reason of your price-to-book ratios, dilute your shareholders' interest, antagonize environmental and community interest, and otherwise bring down more pressure on your existing rates from your State commissions.

The caution that I would like to add is that there is an awful lot now being built into the system that would incline to low estimates of capacity requirements. And I think that there may be a self-fulfilling type of phenomenon being calculated into existing demand for capacity.

Now, that is not to say—I want to make particularly clear that is not to say that there aren't today untapped savings available through least-cost investment strategies, particularly in conservation, and some of the decentralized energy production technologies. They are there, they are substantial, they should be realized and they will be realized over time. They would be realized to an even greater extent if the electric utility industry were to have a better opportunity to profit from those investments than is now allowed in the regulatory systems as they are at present administered.

And for that reason you will hear suggestions that electric utilities be permitted a greater participant ownership in decentralized technologies, an opportunity to earn a greater return on conservation investment commensurate with the rate of return allowed for traditional utility investment.

Those are options that as a matter of national policy I think should be considered.

Mr. FUQUA. Thank you very much.

As I mentioned, I have a bill on the floor and I am going to have to leave, but I am going to turn the chair over to Mr. Wolpe. I will ask Mr. Winn if he has any questions.

Mr. WINN. Thank you, Mr. Chairman. I will yield to Mr. Weber or the gentleman over here first, I think.

Mr. WEBER. Thank you very much. Mr. Curtis, I'd like to explore a little more the idea that we can predict incorrectly on the low side as well as the high side.

Hasn't there been a fundamental change in the situation that a company finds itself in today that is going to inevitably push us to lower demand? That is, with the cost of energy being a major factor, which it wasn't a few years ago, any company seeking to maximize growth is going to have to minimize energy costs the way that companies for the last 50 years have had as part of their strategy minimizing labor costs.

Isn't that going to be inherent with any corporate strategy of growth? Aren't we going to find that the high-growth companies are the ones that succeed most effectively in minimizing energy costs?

Mr. CURTIS. I think energy costs are very significant ingredients in the manufacturing sector, and for certain portions of the manufacturing sector that is more true than others.

While the lockstep relationship of economic growth to growth in energy consumption has been altered significantly, I think it is still true that while not on a one-to-one basis as it used to be, additional growth in the economy is likely and almost unavoidably will lead to some additional growth in our energy requirements.

I do not believe that the price-demand elasticities are negative.

It has been suggested by Amory Lovins that price-demand elasticities for electricity are negative, but I have seen analyses by others of Mr. Lovins' statements that at least suggest to me that that point should be approached with a great degree of skepticism.

Mr. WEBER. Would you accept, though, the proposition that in certain industries the possibility now exists that that relationship could be negative—without saying that it is? At one time that would have been a preposterous suggestion. Everybody would have discarded it. Do you accept that that is today a reasonable hypothesis?

Mr. CURTIS. I would accept that there are certain circumstances in which it could be negative, yes, sir.

Mr. WEBER. Mr. Walker, I appreciate very much your testimony. I'd be interested to know—is the concept of the service corporation being applied all across the State of California, or are you serving just some areas through the Commission?

Mr. WALKER. I think the words used in the invitation letter are most appropriate. The utilities are evolving into a service corporation. We are trying to bring together under one rubric all the activities the utilities do, not consciously as a new strategy but just responding to Federal legislation or some market pressures they see. But essentially all the utilities in California, the municipal and others, are participating in the programs we described.

Mr. WEBER. The reason I asked the question is because Mr. Curtis in the opening parts of his statement referred to the diversification option and other options, and you said the diversification option, I believe, was not widely available—maybe I'm incorrect, but I'd like to discuss it. Since it is available in States like California, there is reason to suggest it might be applicable across the entire country.

Mr. CURTIS. Certainly. The statement I intended to make, in any case, was that it was not equally available to all participants in the electric utility industry. The reason for that is that the Public Utility Holding Company Act of 1935 confines registered holding companies to the business of the operation of a single integrated system and functionally related investments as are appropriate to the efficient operation of that system.

These limitations are not applicable to holding companies which qualify for the various exemptions under that act, nor are they applicable to electric utilities which are not organized as holding companies.

Incidentally, there is not a similar restriction with respect to other types of regulated utilities. For example, interstate natural gas pipelines which are regulated by the Federal Energy Regulatory Commission are earning something on the order of 17.8 percent return on equity. This is not because the Commission is overly generous to pipelines and not to electric utilities, but it is because the pipelines adopted a diversification strategy over the early part of the 1970's which has proved to be of significant advantage in improving their financial circumstances.

Mr. WEBER. Is it safe to say, then, that the inequality of opportunity for the electric utility company diversification strategy, is due to regulatory or legal barriers and not to economic differences or other differences? It is not a problem inherent to a given area of the country; it is a regulatory problem?

Mr. CURTIS. Yes.

Mr. WEBER. That would eliminate the types of things in California Mr. Walker explained to us might be appropriate to varying degrees in every energy market in the country.

Mr. WALKER. We would certainly approve the idea that that type of development could take place. Let me add something to that. I think the Energy Service Corporation and other things I described are close to the electric utility business. So they fall within the confines of the Public Utility Holding Company Act. We are talking about capitalizing those opportunities first before you make it into a wider diversification.

Mr. CURTIS. This is entirely too technical an answer. But I feel the compulsion to add to Mr. Walker's answer. The problem is that when you engage in functionally related activities in dealing with affiliates the entity is confined to do so on a cost plus an allowance for capital equal to the allowed rate of return for the electric utilities, and so the advantage of earning the fruits of the investment for which the risk-taking is undertaken are significantly limited and thus entry to these business opportunities is effectively discouraged.

Mr. WEBER. I am going to have to review the transcript on that answer to be sure I fully understand it.

I have a question to ask of Mr. Walker, which is controversial, but probably you are aware this committee has considered some of these things. The electric utility industry in discussing this problem believes the Government is going to build the Clinch River Breeder reactor and then, in their estimates, around the year 2010 breeder technology will be commercially viable.

My question to you is: In the State of California, given the scenarios that you can reasonably project today, what is your comment on the viability of that type of technology around the year 2010? Can you see a scenario in which that technology would be desirable in a free market condition to meet the energy needs in the State of California?

Mr. WALKER. Not unless California intended to become a major power exporter for the Western United States. I think another option with similar possible global consequences is something like this photovoltaic project. It does not bear any foreseeable relevance.

Mr. **Weber**. I appreciate your response to that question, and I have no further questions.

Mr. **Wolpe**. Just a couple of questions related to global forecasting and some of the methods that have been applied in developing those forecasts.

It has been laid out both by testimony in this panel and by the previous panel that the utility projections of growth in demand have been far in excess of what has happened, for lots of reasons. And alternative projections have been discussed of much lower magnitude. To what extent have those taken into account—or let me rephrase that. Are there projections available that assume the application of such devices as peak-load demand pricing?

My experience, going back for years to the Michigan legislature, was there was just enormous resistance on the part of the utilities to peak-load pricing, and yet from my perspective, looking at the data available then, that seemed to be the greatest opportunity in terms of the avoidance of the building of new powerplants for that peak and would represent enormous savings all around.

I'd be interested in the concept and also your assessment of whatever studies are available.

Mr. **Hemphill**. Let me respond to that briefly. Frankly, I couldn't agree with you more. We have finished a program which will result in putting approximately one-third of our kilowatt hours on time-of-day pricing. It is only 204 customers but it is the largest 204 customers. We anticipate that will not mean that everybody will have to go to work at midnight and all other alleged consequences, but will mean a shift of 2 or 3 or 4 percent of power use from an on-peak period to an off-peak period.

That is an enormous amount of savings. And our load forecasts which are put together will specifically take account of the fact we are changing our pricing structure for electricity, and my anticipation is there will be some very significant and positive effects.

Mr. **Walker**. I think the incorporation of sophisticated rate structures like time-of-use rates and so on has been the last thing the modelers have put on their agenda, and I don't think they've gotten there yet. They are trying to develop this data where people use electricity, how they are responding to it, their average prices, and Government conservation programs, building standards, and so forth.

I think in California we have made a tremendous impact on forecasting ability and are proud of our capabilities. We haven't done much on peak-load pricing forecasts and probably won't for one reason: California's electric utilities for the most part have no peak-load problem. We have 20,000 megawatts of oil and gas-fired capacity that is being moved to intermediate service. So we see our reserve margin going from a somewhat tight margin now to more comfortable in the future as those oil-fired plants move to standby status.

Mr. **Wolpe**. I have often wondered what a requirement that before the decision would be made to build a new powerplant, that there be an effort to develop a pricing system—what national impact that kind of requirement would have on new powerplant construction. Does anyone want to respond to that?

Mr. **Hemphill**. I think my basic instinct is you are probably correct, but you have to understand some of the difficulties of making that case conclusively. And that is that our information on elasticity of demand, which is really what you're talking about, is not real wonderful with respect to gross consumption in order to accurately predict how people respond to peak-load pricing. You need to know what their elasticity of demand is at 6 in the morning and at noon and at 10 in the evening.

That is a whole lot more information than one is really comfortable with in terms of its reliability. So I think that is another reason why the forecasters have not got around to that one.

Mr. **Wolpe**. You have an additional 30 seconds. The bell is sounding, and we must race over for a vote. But I'd like to invite any additional comment.

[No response.]

Mr. **Wolpe**. With that, I'd like to thank all of you for testifying today. You have been very helpful. Thank you very much.

[Whereupon, at 12:30 p.m., the hearing was adjourned.]

THE FUTURE OF THE NATION'S ENERGY UTILITIES: IMPLICATIONS FOR FEDERAL R.D. & D.

WEDNESDAY, JUNE 24, 1981

House of Representatives,
Committee on Science and Technology,
Subcommittee on Energy Development and Applications,
Washington, D.C.

The subcommittee met at 9:35 a.m. in room 2318 of the Rayburn House Office Building; Hon. Don Fuqua (chairman of the subcommittee) presiding.

Present: Representatives Fuqua, Harkin, Ertel, Fish, Weber, Schneider, McGrath, and Dunn.

Mr. Fuqua. The subcommittee will be in order.

Today, we begin the second day of hearings on the future of the Nation's energy utilities and the implications for Federal R.D. & D. programs that are authorized by this committee.

Yesterday, we had six witnesses that gave very stimulating and sometimes different testimony, and today I am sure that we will likewise be in that situation. We do have several time problems. Sometimes when you schedule hearings well in advance, you're not aware of other contingent matters that may happen. The House goes in session today at 10 o'clock, and we do have other problems. So we hope that the witnesses, if they can, can summarize their statements in maybe 10 minutes or less.

I'm sure, if today is a repetition of what happened yesterday, there probably will be more stimulating discussion in the questions and interplay than maybe even in the testimony itself.

We would like to take our witnesses in a panel and will start off with Mr. Joseph Swidler, a member of the law firm of Leva, Hawes, Symington, Martin & Oppenheimer.

Mr. Swidler, it's nice to see you. I know a couple of your law partners very well—Mr. Leva and Mr. Martin. Give them my regards.

Mr. Swidler. I certainly will.

Mr. Fuqua. And Mr. Swidler will be followed by Mr. Guy Nichols, the chief executive officer of the New England Electric System; Mr. Irwin Stelzer, president, National Economic Research Association; Mr. Ralph Mitchell, vice president, conservation and renewables with Arkansas Power & Light; and Dr. Jay Kennedy with ELCON here in Washington.

So, Mr. Swidler, if you would lead off, we will be happy to hear from you.

STATEMENT OF JOSEPH SWIDLER; LEVA, HAWES, SYMINGTON, MARTIN & OPPENHEIMER, WASHINGTON, D.C.

Mr. **Swidler**. Thank you. If I might say, I have been associated with the electric power industry one way or another for 51 years, and during that period, I worked for the Federal and State governments 34 years, and I have spent the other 17 years waiting for offers. [Laughter.]

Although my law firm represents a number of electric utilities, I do not speak for any of them or for the industry, and the views I am about to present are just my own, reflecting my work for the Tennessee Valley Authority, for the Federal Power Commission, New York State Public Service Commission, as well as any experience in private practice.

Now I had intended just to say a word or two about the financial condition of the electric utilities, but I understand that was a subject covered pretty intensively yesterday.

I would like to draw your attention, however, to the copies of the Argus Utility Scope prepared by the Argus Research Corp. which are attached to the written copies of my statement, which I don't intend to read. I particularly call your attention to the first three lines which show first the authorized rate of return on equity by the State utility commissions of the country for the 50 largest electric companies. As you see, it is a rather uneven history, but it trends up from 12.5 percent in 1972 to 14.3 percent in 1980, partly estimated.

The next line, however, shows that this authorized rate of return was not earned, that the actual rates authorized fell far from permitting the utilities to achieve this return on equity. And in this period of growing financial strain, wild inflation, the escalating cost of money, the earned return in that period actually declined and was at its lowest level in 1980. The difference represents what is called attrition. In 1972, the commissions came pretty close to permitting the utilities to earn what they purported to allow, within two-tenths of a percent. That grew almost year by year until in 1980 the difference was 3.3 percent which really identifies the worst regulatory failure—that they have not matched their rate allowance with their earnings awards.

The other line I would like to call attention to is line 5 which shows the growing percentage represented by the book item of allowance for funds used during construction, which isn't money—can't buy anything. It was something like 5 or 10 percent in the 1960's, 30 percent in 1972, and had almost doubled to 58 percent in 1980 so that for the 50 largest utilities, almost 60 percent of their reported earnings on common equity was just a paper item. That, of course, has a severe impact on the credit of the utilities and the cost of the money they must borrow and raise by sales of equity.

Now, I made a talk in Ames last month on why the utility commissions have been so remiss, and I speculated there on the reasons. I have copies here, and if the Chair is interested, why I'd be glad to have that part of the record.

Mr. **Fuqua**. I would be delighted to look at them. We'll certainly make them a part of the file on the hearing.

[The document referred to follows:]

20TH ANNUAL REGULATORY CONFERENCE
IOWA STATE UNIVERSITY
AMES, IOWA

The Plight of the Electric Utilities and the Testing of Regulation

Joseph C. Swidler

May 19, 1981

Most of you, I am sure, are familiar with the history of the electric utility industry's course of earnings decline and loss of credit. The depressed stock prices, the lowered ratings on utility securities, the vanishing margin of debt coverage, the decline in quality of earnings, and the flood of generating plant cancellations and deferrals, all bear witness that from a financial standpoint the industry is a sick industry, and that utility regulation no longer provides protection against the earnings risks for investors. Attached to the written copies of this talk is a data sheet prepared by Argus Research Corporation which brings together many of the key indicators of the poor financial condition of the nation's power companies.

A side effect of the financial problems of the regulated electric utilities is the gradual shift of market shares to the unregulated sector. Duke Power Company provides an illustration. Carl Horn, Chairman of Duke Power Company, explained the process in a recent interview.

> "Duke cannot stop building altogether. 'We just want to keep our expansion at the very minimum,' says Horn. Duke has about $3.6 billion worth of capacity under construction and slated for operation in or before 1986 -- an overall 39% expansion in capacity. But it managed to finance that only by selling nearly half the new capacity to publicly owned rural and municipal customers in North and South Carolina who are expected to pay an estimated $1.8 billion. 'The day existed when we wouldn't have done this on principle,' says Horn. "But when survival becomes the issue, philosophy goes out the window.' Duke shouldn't need outside financing until 1982. (Forbes, January 5, 1981, p. 217.)

A considered program of public ownership is one thing. A slide in that direction, caused by the rigidities of regulation, is quite another. This slide is another reason for regulatory self-examination.

Learned studies have brought the resources of scholarship to demonstrate the extent of regulatory failure in dealing with the electric utilities, and the reasons. These studies have brought new insights into the dynamics of utility regulation. A number of them are summarized in a recent article in the Journal on Government and Society by Peter Navarro, a teaching fellow at Harvard.1/

1/ Navarro, Electric Utility Regulation and National Energy Policy, AEI Journal on Government and Society at 20 (Jan./Feb. 1981).

First, Dr. Navarro sorts out the utility commissions on the basis of rankings on six objective criteria which are used by some of the leading investment firms in their analytical work. These are the (1) allowed rate of return, (2) treatment of CWIP, (3) regulatory lag, (4) normalization, (5) future test year and (6) automatic fuel adjustment clause. Eight states were put in a very favorable category based on this mix of standards. I know you are curious about the winners. They were Arizona, Florida, Hawaii, Indiana, New Mexico, North Carolina, Texas, Utah and Wisconsin.

In a middle category were 21 states and the District of Columbia. The unfavorable category consisted of 15 states, among them California, a New England group which included Connecticut, Maine, Massachusetts and Rhode Island, a southern group consisting of Alabama, Georgia and Mississippi, and several others.

One of the studies cited by Navarro demonstrated that an unfavorable regulatory climate was a major factor in explaining low bond ratings. The cost of bond money is higher for the utilities in the states with an unfavorable regulatory climate, equity money may cost as much as 2 percentage points more in such jurisdictions, about the same as the additional cost of debt, and the market-to-book ratio tends to be far lower. Where dilution is heavy, management resists raising equity capital and as a result tends to curtail construction programs drastically.

The difficulty in raising money means that those utilities which depend on oil and which are located in states with a poor regulatory climate are unable either to convert from oil-fired plants to coal or to build substitute capacity, even when it is demonstrable that the investment in new nuclear and coal-fired plants would soon be repaid in consumer savings.

Navarro undertook to identify the factors which determined the regulatory climate. One was political pressure, which was greatest in the states where the regulators were appointed or where their terms were short. The extend of funding for the regulatory agencies seems to have made a difference, although I must say that the rankings of New York and California, which have the largest staffs by far, make me wonder about this correlation. Dependence on appropriations rather than assessments was a negative factor. A final consideration was what was called the "ideological variable" by which is meant the "liberal" state of mind which is likely to "use a PUC to effect income redistribution for the benefit of traditionally favored groups such as consumers."

It appears also that the larger the number of Democrats in the regulatory body, the more likely for the state to have an unfavorable rating. The greater the dependence on oil, and therefore the greater the pass-through of fuel costs, the more intense is the opposition to rate increases, despite the fact that in these states investment in new capacity would do the most good in the long term.

Professor Paul Joskow in a 1974 study[2] concluded that regulatory commissions historically seemed to be more sensitive to changes in prices than to rates of return. This is an elegant way of saying that commissions are reluctant or unwilling to grant rate increases in the face of consumer opposition. If the conclusion is unsurprising, it's implications often go unrecognized. It raises difficult questions of reconciling regulatory performance with the obligations of office.

I can recall, from my own experience as a member of the New York Commission, listening to arguments in rate cases in which the conflict between consumer pressures and official duty was presented in the most acute way. Consumer representatives, usually speaking for domestic consumers, and particularly those with low income or dependent on public welfare, would make impassioned arguments as to the burden of the rate increases. Typically, they made no effort to familiarize themselves with the record of the case. The questions of earnings trend, fair rate of return, company credit, the interests of stockholders, ability to build for the future, and even the long-term interests of consumers in continued electricity supply on an economic basis, were ignored. Indeed, there was little that they had to say that was legally relevant to the decision, which the Commission was required under the law to reach on the record. But the spokesmen for the consumer groups, who regularly painted the Commission as a captive of the regulated companies, received the greatest prominence in the news stories. After a few minutes of this kind of argument, these spokesmen would leave the hearing room to make corridor statements to waiting reporters and television crews. Then they would disappear from the scene. I should be surprised if this scenario was not fairly common throughout the country.

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[2] Joskow, Vol. 17 J. Law and Economics 291 (1974).

I do not doubt that some of these consumer representatives lack the means to hire expert witnesses or otherwise to present germane testimony, or even to cross examine the witnesses produced by other parties. But they rightly perceived that they could not have an impact based upon record evidence or an analysis of the legal issues. They understood correctly that if they were to have an impact, it could only be through political means, and they had become expert in the application of political pressures. Indeed, they were successful in creating an environment in which the members of the Commission and the staff approached their responsibilities with great defensiveness because they knew that any rate increase would be attacked as an evidence of callousness to the plight of the poor and of susceptibility to the claims of the regulated companies.

At best, a utility commission is in a difficult position to resist such pressures. A comparison with the judiciary explains why. Typically, judges have long tenure to protect them from political pressures, while utility commissioners serve relatively short terms. Judges preside over a complex mix of business, most of which attracts little public notice, while commissioners are appraised on the basis of a series of rate decisions, all bringing bad news. The selection process for commissioners is typically less rigorous than for judges. The press and the public understand that respect for the independence of the judiciary is indispensable to social order, and this understanding prevents facile accusations of bias or prejudice. The same is not true of the public attitude toward the utility commissions. They are vulnerable to accusations of favoritism to the utilities, however honorable, courageous and wise they may be, or even if their rate awards are far too low to preserve the financial soundness of the utilities. The only way for a commissioner to avoid being criticized for partiality to regulated companies is to deny all rate increases, which is hardly a practicable course in a continuing inflation.

A commissioner, like a judge, is required to decide a case on the record. His decision is subject to judicial review and in the review process he cannot defend a decision by claiming that a rate increase was opposed by consumers or that it would fall hardest on poor people. Rather, to avoid rate increases it becomes necessary for commissions to disallow as many items as possible from rate base and expenses, to capitalize expenditures whenever possible, as with construction work in progress, to under-estimate future expenses, and to delay recovery of increases in costs. These are some of the ways "sensitivity to changes in prices" tend to manifest themselves in rate cases.

These approaches are not applied in a deliberate way, in my opinion. Nevertheless, the sensitivity to rate increases exerts a powerful effect in deciding the issues in rate cases. Otherwise, it is almost impossible to explain the large and growing discrepancies between allowed and realized rates of return on equity, which a decade ago was only two tenths of a percent, and is now fifteen times as large. There can be reasonable argument about the allowed level of return, but what can be said of the consistent failure, by growing margins, to permit rates which will earn the returns the commissions themselves recognize as the minimum just and reasonable earnings?

A not infrequent reaction of utility commissioners to criticisms of this sort is one that I heard expressed by the statement, "I don't want to hear any more lectures on my duties." Indeed, the position of a utility commissioner is frequently very unhappy. The problems of the poor, who face increased costs of all kinds, without the means to pay them, is poignant. There are many consumers who can only pay their utility bills at the expense of food or rent or other basic needs. This is a problem, however, not limited to the utilities. Every time the poor buy groceries, or anything else they need, they will find new markups. Prices for utility services cannot be made the balancing factor for the inroads of inflation upon the poor. Congress and the state legislatures must make the difficult decisions on how much of our national resources to dedicate to establishing lifelines for the poor, giving consideration to all their needs, including utility services.

There is an overriding need to maintain the economic infrastructure upon which all of us must depend in the future, and electricity supply is among the most important elements of that infrastructure. The poor will need help not only now but in the future, and their economic horizons will be lowered, not raised, if society fails to provide the energy needed for new industry and more jobs. Of course, it is the obligation of the utility commissions to disallow any revenues that are not necessary to assure low costs over the long term, the ability to attract capital and the other elements of a fair return. At the same time, it is their obligation to allow the rates which are necessary to provide an economic power supply for the future. Somehow, the regulators must face the need to adjust their rules and procedures so that they can carry out their responsibilities under the law.

The appointing officers sometimes contribute to blurring the line of responsibility of regulators. In one state in the East it was reported recently that the Governor had nominated to the utility commission a person he designated as a "consumer representative." The implication is that the other members were not also consumer representatives. Obviously such an appointee would have reason to think the obligations of the office would be different than for the other members of the commission, even though all took the same oath to uphold the law "without mental reservation or purpose of evasion." And, as stated by the U.S. Supreme Court in a 1973 gas pipeline case which is equally applicable to electric companies:

> "As already noted, under Hope Natural Gas rates are 'just and reasonable' only if consumer interests are protected and if the financial health of the pipeline in our economic system remains strong." [3]

This is not a criticism of commission appointments from consumer ranks. The illumination of experience in prior employment can make a contribution to insights and perspective, but everyone who is appointed should meet the basic test of freedom and ability to decide a case on the record.

It is sometimes said that the cure for the problems of the utilities is to stop inflation. This may be true, but inflation is an intractable problem. It rests not only on deeply embedded domestic factors, such as indexing of prices for commodities, wages, pensions and welfare, but is also driven by a world-wide set of forces - among others, the need to help support the world economy, OPEC pricefixing, and the pressure of the USSR, which forces up military budgets and foreign aid. We should not rest our hopes for the future of regulation and the regulated industries on the assumption that

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3/ F.P.C. v. Memphis Light, Gas and Water Division 411 U.S. 458, 474.

inflation will be cured. Regulation must function, and function fairly, if inflation endures. An industry cannot survive if its prices are rigid and its costs are elastic.

Professor Joskow, in the article to which I have referred, concluded that the thread running through the history of regulation is an effort by the regulatory agencies to seek a new equilibrium following a disequilibrium period created by new conditions. Despite the failure of regulation thus far to adjust to the new economic order of the utilities caused by inflation, new environmental and safety concerns, sky-rocketing fuel prices and unprecedented levels of money costs, one can see the beginnings of this process of change. Two recent proceedings initiated by the FERC, one an effort to devise a new and more expeditious method of determining rate of return,4/ and the other a generic investigation of the financial condition of the electric utilities5/ are the most conspicuous examples.

The FERC rate of return proceeding is the first in this country so far as I know, which in a straightforward way is casting about for a fairer and more workable method of fixing rate of return allowances

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4/ Rate of Return on Equity for Electric Utilities, Docket No. RM80-36.

5/ Informal Inquiry into the Financial Health of the Electric Utility Industry, Docket No. EL81-7-000.

for the electric utilities. It is based on the report of a Staff Study Group which conceded the breakdown of the present regulatory process:

> "In short, the Study Group concludes that Commission decisions on wholesale electric rates of return, as represented by the derived weighted averages, appear to have failed to reflect the realities of the marketplace.... Based on its review, the Study Group questions whether the Commission's legal and economic objectives can ever be realized in setting rates of return for the electric utility industry using current procedures and methodologies."6/

The weighted average rates of return of the FERC, I might add, appear to be no worse than those of the state commissions.

In the investigation of the financial condition of the electric utilities the FERC, again for the first time, is attempting to look at the forest rather than the trees, and to appraise the overall financial condition of the electric utility industry under regulation. Where this proceeding will go is uncertain. However, if the FERC should pursue this study, and conclude that regulation is not working insofar as electric utility ratemaking is concerned, I presume it will have no choice but to contribute to the process of seeking a new regulatory equilibrium.

6/ Discussion Paper on Electric Rate of Return prepared by an FERC Staff Study Group, dated December 15, 1980.

There has been movement at the state level as well. Many commissions have allowed CWIP in greater or smaller measure. Test years are gradually moving up and forward test years are not uncommon. These are good signs and while they are overdue, they represent at least the beginnings of the process of seeking a new equilibrium which will permit the survival of private enterprise in the supply of electricity. They probably account in large part for the gradual improvement in allowed rates of return. Thus far, these measures have not had a discernible impact on the average level of realized earnings. The commissions have moved too haltingly in seeking to adjust to change. What they have given with one hand they have taken away with the other. One can only hope that the adjustment to a new equilibrium will be made while the regulated utilities are still viable enterprises for serving the electric power needs of this country.

Regulation by quasi-judicial agencies is a unique American institution. Its success has made it possible to develop the electric industry in this country with private capital and enterprise. But it rests on a fragile foundation of faith in regulatory fairness in reconciling consumer and investor interests. The managers of the regulatory institution have a profound responsibility to demonstrate that regulation can operate fairly even under the testing conditions which confront them.

Argus UtilityScope
REGULATORY SERVICE

ELECTRIC UTILITY INDUSTRY
SELECTED STATISTICAL/FINANCIAL MEASURES 1972-1980E*

Financial/Statistical Measures**	1972	1973	1974	1975	1976	1977	1978	1979	1980E
1. ROE Authorized (%)	12.5E	12.5E	13.0	13.2	13.1	13.3	13.2	13.5	14.3
2. ROE Earned (%)	12.3	11.7	10.6	11.3	11.7	11.8	11.5	11.3	11.0
3. ROE Attrition (%)	0.2	0.8	2.4	1.9	1.4	1.5	1.7	2.2	3.3
4. Fixed Charge Coverage (X)	3.01	2.92	2.54	2.67	2.85	2.95	2.90	2.72	2.5
5. AFC as % Balance for Common	30	32	41	36	35	36	47	50	58
6. Effective Tax Rate (%)	22	21	19	24	26	29	29	26	24
7. Market/Book Ratio (Revised)	1.2	1.0	0.7	0.7	0.8	0.9	0.8	0.7	0.8
8. Dividend Payout %	64	67	63	64	64	66	70	71	74
9. Yield on "Aa" New Issues (%)	7.4	7.8	9.5	9.5	8.7	8.3	9.1	10.5	12
10. Authorized ROE vs. "Aa" Yield (%)	+5.0	+4.5	+3.6	+3.7	+4.3	+5.0	+4.1	+3.0	+2.5
11. Earned ROE vs. "Aa" Yield (%)	+4.9	+3.9	+1.1	+1.8	+3.0	+3.5	+2.4	+0.8	—1.0
12. CPI % Increase	3.3	6.2	11.0	9.1	5.8	6.5	7.7	11.3	13.4
13. Cents/KWH Residential Customer	2.42	2.54	3.09	3.51	3.73	4.06	4.31	4.63	5.2
14. Cents/KWH Increase (%)	4.3	5.0	21.7	13.6	6.3	8.8	6.2	7.4	12.3
15. Net Plant Increase (%)	12.2	12.7	11.0	8.7	9.9	10.3	10.2	10.5	9.5
16. KWH Sales Increase (%)	8.2	7.6	(0.6)	1.5	6.3	5.1	3.5	2.9	1.5
17. Plant Inc. vs. Sales Inc. (%)	+4.0	+5.1	+11.6	+7.2	+3.6	+5.2	+6.7	+7.6	+8.0
18. Construction Spending ($Bils.)	12.3	13.5	15.0	13.4	15.2	17.1	19.7	22.1	24

E - Estimated. *Compiled by Argus Research for panel presentations September 29, 1980 at 1980 Joint Power Generation Conference and November 19, 1980 at workshop on Rate of Return/Earnings Regulation. **Measures explained in footnotes below.

FOOTNOTES

1. Simple average of the returns on equity authorized major electric utilities.
2. Simple average of the earned returns on equity for the 50 largest electric utilities followed by Argus Research.
3. The percentage points by which the return on equity authorized exceeded the return on equity earned (line 1 minus line 2).
4. Simple average of the pre-Federal income tax interest coverage ratios of the 50 largest electric utilities followed by Argus.

5. Simple average of the allowance for funds used during construction percentages of balance for common stock of each of the 50 largest companies.

6. Simple average of the effective Federal income tax rates of each of the 50 largest utilities.

7. The average market price to book value ratio for Moody's 24 electric utility index.

8. Average dividend payments as a percentage of share earnings for Moody's 24 electric utility index.

9. Average yield on new issues of electric utility bonds rated "Aa", as compiled by Moody's.

10. The percentage points by which the authorized return on equity was greater than the average "Aa" bond yield (line 1 minus line 9).

11. The percentage points by which the earned return on equity was greater than the average "Aa" bond yield (line 2 minus line 9).

12. The annual rate of change in the Consumer Price Index from the prior year.

13. The average price paid by residential customers of investor-owned electric utilities, in cents per KWH.

14. The year-to-year percentage increase in the prices paid by residential customers.

15. The percentage year-to-year increase in the net plant investment of the investor-owned electric utility industry.

16. The year-to-year percentage increase in total electric sales by all investor-owned electric utilities.

17. The percentage points by which the increase in net plant was greater than the increase in electric sales (line 15 minus line 16).

18. The total construction spending by the 50 largest electric utilities followed by gus Research, in billions of dollars.

9/29/80

Mr. **Swidler**. Very good.

Now, one of the worst features of the scene from the point of view of the utilities is the additional risk they see being imposed on them, and perhaps the worst of them now is the risk that when these plants are finally completed and under normal rules would become part of the rate base and the utilities would begin to earn cash returns on that investment, the utility commissions are saying, "Well, let's take a look at it before you put it in the rate base. Let us decide now whether you should have built a plant in the first place." And inasmuch as these plants frequently represent as much as the whole common equity of the company, this is a very serious risk and burden which has further depressed the securities and the outlook of the utilities.

I tried to look into the future and see what this might mean for the utilities, not only in relation to their R.D. & D. work, but the kind of perspective that they will apply to doing their business, and, of course, looking in the future is always risky, and my own record on it is not all that good, but I made the effort anyway.

Mr. **Fuqua**. We have all had problems with that.

Mr. **Swidler**. In general, I think we can expect—and will you give me a couple of minutes more, please, Mr. Chairman?

Mr. **Fuqua**. Sure.

Mr. **Swidler**. In general, we can expect, I think, that the utilities from now on will be operating defensively. They will minimize their investment to the extent they can, and they will try to avoid risk. This, in turn, means they will not be in the position, as they have been in the past, to optimize for long-term economy and efficiency. The first cost will be a much more serious consideration now than it has been in the past. They will trim their budget to what they can afford. Many of them will not be able to afford—and this is a real tragedy—conversion of plants from oil to coal. This represents heavy first cost in most cases, and the money is not available. Unless the Federal Government helps with the financing, that program will lag, and there will be no new starts for a while.

So far as existing plants are concerned, the companies have a tiger by the tail. But not many companies are going to be risking the future of the enterprise on starting one of these large, new installations. Certainly not until there has been a great improvement in the licensing process for both nuclear and coal and especially nuclear. The nuclear licensing process, the environmental licensing process, are not credits to the administration of government in this country. They badly need improvement, and a large part of the burden of inefficiency imposed by the processes are borne by the electric utilities.

They will push load management very hard—conservation, innovative rate designs, interruptable loads—anything that will help to reduce the need for new capacity. They will be selling off their interests in new plants in large part to the public and cooperative systems which have access to Federal tax-free financing. And that, in turn—that doesn't mean there will be a reduction in financing needs. It doesn't mean a reduction in costs; it means a shift of the burden to the Federal taxpayer.

If alternative technologies prove cost-effective and environmentally acceptable, they will, of course, be used. Of course they represent one of the ways of achieving a reduced investment requirement. Reserve margins are going to be reduced, especially toward the end of the 1980's.

Now what this means to the U.S. economy is a difficult question. If loads grow at the low rates which are contemplated in some of the forecasts, it may not make much of a difference for the long term. If there is a higher growth rate, if we approach the higher estimates which have been made, this country may be in for some serious trouble.

One of the problems is that these estimates tend to be self-fulfilling. Industry is not going to locate plants if it doesn't have assurance of power supply, and employment will be seriously affected. There may be a great locational shift, depending on the power supply availability. All this is on the assumption that the people who have made the lowest estimates prove to be wrong. And that's something I'm not an expert on myself. My feeling is that loads will grow somewhere between the low and the high estimates.

There will be more cogeneration, more industrial generating plants. The companies will try to remove artificial constraints on institutional improvements and their ability to do a good job for themselves and for their customers. They will want to participate in diversification enterprises, especially those related to the expertise they have accumulated in running the electric power business.

I should say a word about R.D. & D., which I know is a principal interest of this committee. R.D. & D. is risk money, and I think that there isn't going to be a great abundance of that available, especially with the shortage of money for the prototypes of large pieces of equipment. These demonstrations are very expensive, and if there is no market, the manufacturers aren't going to be interested in carrying the loads, and neither will the utilities. So I would expect a slowdown on technological development in large stations except for improvements in safety, efficiency, and reliability for existing plants. That will go forward.

I would like to comment, finally, on the deregulation of generation which has been proposed by a number of students of the industry as a solution for its problems. I am frank to say that I have yet to understand the proposals because none of them so far has really addressed the specific problems of the electric power industry that they would run into in attempting deregulation.

For example, unlike, I believe, any other industry, the electric power industry has a public and a private sector, and the public sector enjoys tax exemptions. Purchasers of their securities pay no taxes on the interest on the bonds that they buy. The Federal Government has accorded public systems preference to the Federal power supply. The public systems are great encouragers of new hydro and other plants by the Federal Government to which they would have preferred access to the exclusion of the private systems.

Now it's obvious that is you were to have competition, all that you would prove is something that I think most of us who pay taxes have already guessed—that it's cheaper not to pay taxes than to pay them. And I don't think it would mean any social saving or reduction of real cost, but again a shift of the burden to the federal taxpayer.

A second problem is that these installations are fixed installations of very high cost. Unlike buses and planes, you can't move them around to where the business might be better. You can't sell them off as used equipment. My own experience leads me to think that nobody will build a plant of that sort without a firm guarantee of sale of the output at a profitable price, come hell or high water. This is a familiar concept in the utilities industry, and I wouldn't expect that any capacity would be built on any other terms. And if these are the requirements, where would be the savings?

Moreover, if transmission is not deregulated and distribution is not deregulated—if neither of those are unregulated—then the regulators have two more cracks at the generating cost, indirectly, in deciding what costs to pass through from the generating plant, so that the practicability of these suggestions is not apparent to me. None of these proposals have been fleshed out, and maybe somebody can prepare a detailed proposal that would face these problems, but I haven't seen any.

If I can conclude now, I would like to remind the members of the committee that this is, I think, the only country in the world in which private capital represents the bulk of the investment in electric power supply. And this has happened because of an implicit compact under the Constitution that if investors put their money into the electric power and other utility businesses, that the regulatory agencies under the Constitution will be required to accord them due process and a reasonable return on the investment.

Now that compact under inflationary conditions has not been working, and the courts, since they stopped in the 1940s looking into the details of the administration of rate cases and said they would only look to the overall result, have not provided any direction to the utility commissions in performing their job, so that now the utilities are confronted by a regime where they do not have the constitutional guarantees in a form that they can rely upon.

There are signs of improvement. There are new proceedings, especially at the Federal Energy Regulatory Commission, which indicate an awareness of the need to accord the utilities enough earnings so that their credit will make it possible for them to grow and to invest and to provide reasonable returns to their stockholders, but it is too early yet to say that the regulatory situation is going to cure itself.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Swidler follows:]

STATEMENT OF JOSEPH C. SWIDLER

COMMITTEE ON SCIENCE AND TECHNOLOGY
Subcommittee on Energy Development and Applications
House of Representatives

Washington, D. C.

June 24, 1981

Mr. Chairman and Members of the Committee:

I am pleased to be invited to testify today. The Chairman has requested that I discuss the financial status of the electric utilities and the outlook for the electric utility industry, including institutional and regulatory reforms, and my testimony is directed to these subjects.

I am a member of a law firm which represents a number of major electric utilities. However, I am not testifying on behalf of the industry or of any company. This statement presents my own views, based on a 50-year association with the electric utility industry, including service as General Counsel of the Tennessee Valley Authority, Chairman of the Federal Power Commission and Chairman of the New York State Public Service Commission. This is not to suggest that either years or diversity of experience assures reliable judgments on policy questions. I know that frequently they merely contribute to a mistaken certitude of opinion.

Since financial experts have testified on the first day of these hearings, I shall not discuss at length the details of the financial plight of the investor-owned sector of the electric utility industry, which accounts for about three-fourths of the total industry. However, I call attention to the attached statistical summary prepared by Argus Research Corporation, which reports some of the key financial figures for the 50 largest electric utilities, for the nine years 1972-1980. The 1980 figures, you will note, are estimated.

The most significant figures are in the first three lines. In 1972, the utility commissions of this country authorized rates of return on the common equity of these companies which averaged 12 1/2%. (The rate of return on investment in all years was much lower because it reflected the lower cost of embedded debt.) Over the course of the next eight years, reflecting inflation and other cost factors to a degree, the authorized rate of return on the average gradually increased to 14.3%, in 1980. Line 2 shows that the rate increases authorized by the commissions did not permit the utilities, in any year, to earn the return on equity which the commissions purported to allow. In 1972, the utilities earned 12.3% on their common equity. Those earnings were not equalled in any of the succeeding years of spiralling inflation. In 1980 it was only 11%, the lowest average return on equity in the entire period, except for 1974.

The difference between authorized and earned return is sometimes referred to as "attrition". This factor is shown in line 3. In 1972, the utilities earned almost as much as the regulatory commissions authorized, the difference being only two-tenths of a percent. But as the allowed return increased, so did the attrition. In 1980, attrition had grown to 3.3%, 16 times as much as in 1972. The whole of the purported increases, and more, was accounted for by attrition. What the commissions conferred with the right hand, they withdrew with the left.

The erosion of reported earnings is not the whole story. The quality of the earnings also has declined. Line 5 shows the data on declining earnings quality. In 1972, 30% of reported earnings available for common stock consisted of an allowance for funds used during construction (variously known as AFC or AFUDC). This reported revenue item does not represent cash revenues. It is not money. It will not buy anything. It is purely a book item, in which the utilities report the carrying charges on the plant excluded from rate base because it is still under construction. By 1980 this book item had almost doubled, to 58% of earnings available for common stock. This means that for many utilities it was necessary to issue new securities, both bonds and common stock, in order to pay dividends, and even interest on debt in many cases.

Investors are rightly concerned when a major share of reported earnings represents a mere bookkeeping adjustment. So are the utilities. The AFC treatment is not the only way to handle investment in plant under construction, and it is certainly not the best under present circumstances. The most straight-forward way is to place the investment in rate base as it accumulates. This is the CWIP (Construction Work In Progress) method. Not only does it provide a cash return when cash is badly needed, but it also reflects the marginal costs of new capacity, and therefore sends appropriate purchase signals to investors. It permits gradual adjustment to new cost levels, and avoids the abrupt increases which characterize the AFC system. But AFC treatment permits postponing the rate increases required by the recognition of present-day costs. That is its great charm for the regulators. Of course, investors suspicious of AFC treatment exact a higher cost for new money, so that in the long run the consumer is not well served.

The whole Argus table bears study, but I shall call attention to only one more comparison, between the percentage increases in the Consumer Price Index, as shown in line 12, and the increases in kilowatt-hour costs shown in line 14. In some years, and particularly in the years of adjustment to the astronomic increases in fuel costs which followed the 1973

Arab-Israeli War, the cost of electricity substantially exceeded the general inflation rate. In the last three years, however, electricity cost increases have trailed inflation.

The financial picture I have described has had a severe effect on the credit of the utilities and on their cost of raising new money. Bond ratings have deteriorated year by year, to the point that the utilities, once treated as prime credits, have become high cost borrowers. Common stocks sell at roughly three-fourths of book value, and must pay high dividends to sustain even these values. For most utilities each new issue of common stock involves a severe additional dilution of the stockholders' equity, represented by the common stock which was already selling at distress prices. The higher cost of bond money is, of course, reflected in the cost of utility service, which ultimately must be paid for by the rate payers. Much of the high cost of equity money comes out of the hides of existing equity investors.

Some of you may be wondering why, under these circumstances, the utility commissions are so remiss in providing adequate revenues to the electric utilities. The answer is not altogether clear. I believe the main reason is that these prices are politically sensitive. They are fixed in open proceedings in which any consumer may participate, and they have become the focus of consumer resentment against all the painful effects of inflation. Consumers do not have a similar opportunity to express their anger at increases in the prices of all the things they buy -- food, clothing, drugs, shelter. Utility prices have become the surrogate for general price inflation. It is not easy for a utility commission to authorize an increase in rate of return, but the commissions have at least partially faced reality on this score. What comes much harder for them is to accompany the increases in the rate of return allowances with rate increases -- real money -- in amounts large enough for earnings to match allowances. Here, they have been reluctant to carry out their responsibility to prescribe the just and reasonable rates required by law. The failure is understandable. The regulators do not seek the prize in an unpopularity contest. But it is not excusable.

The investor-owned electric utility idnsutry represents an investment of well over $100 billion dollars and requires new investment every year of an additional $20 billion dollars or more. It is the most capital intensive of all the industrial sectors. Half of the new common stock money raised by American industry represents electric utility issues. In the past, public utility investments reflected the confidence of investors in an implicit compact with regulators that in return for investing in this price-regulated industry, due process under the federal and state constitutions assured a fair return on the investment. The figures I have given you demonstrate that this compact is being broken by the regulatory agencies. In periods of declining costs they were, on the whole, up to their responsibilities. In the extended period of bad economic weather represented by the 70's, however, they have been unable to function in such a way as to protect investors and to assure an adequate flow of funds for the future needs of the industry.

At the 20th Annual Regulatory Conference at Iowa State University on May 19, I probed the reasons for this regulatory failure in a talk entitled, "The Plight of the Electric Utilities and the Testing of Regulation". If the Committee likes, I should be glad to have this talk made a part of the record.

An ominous development of recent months has been state commission action which has created a growing uncertainty as to whether, when a generating plant is finally completed, the state commission will allow the investment in the plant in rate base. One of the side effects of the AFC treatment of investment in plants under construction is that consumers do not assume the burden of carrying the capital costs gradually, as money is invested, but rather all at once, when the plant is completed. At this time they must pick up not only the actual cost of construction, but also the AFC account, representing carrying charges through the construction period, which may add as much as another 40% to the book cost of the plant. Considering that new plants are coming into service at several times the cost of the old plants, the sudden rate effect of adding the entire new plant investment to rate base can be severe. When the commissions finally are confronted with the rate consequences of AFC treatment, some cast about for ways of escape.

In several states the commissions are conducting proceedings to determine whether completed plants are really necessary, after all. With all the benefits of hindsight, and with a keen sense of political realities, they are looking into the question whether a plant authorized 10 or 15 years ago should have been built at all. Keeping in mind that such a plant, built in the last decade of developing inflation, may represent a company's whole net worth, and more, it becomes possible to understand the awkward position of utility managements and directors, in these states and others, who may be asked to authorize new starts on plants which will not be completed for another decade or more, and which will come into service under presently unpredictable conditions. The gamble is not appealing. If the utilities are lucky they will recover their costs, but only barely. On the other hand, they may not be lucky.

It is easier to describe these regulatory problems than to appraise what they portend for the utilities. If one were merely to extrapolate from recent trends, the indicated results would indeed point to disaster for the industry, and grave trouble for consumers and the economy of the country. Simple extrapolation almost always fails to predict a distant future, especially in a dynamic society and a turbulent world. There are some corrective forces at work. I doubt that the industry as a whole will be able to return to the days of a single-minded focus on optimization of efficiency, adequacy and reliability of service, but some companies may do so, and as an entity the industry will continue to do a creditable job.

What are the changes that are now going on, and what should we expect in the future? Notwithstanding an indifferent record in the prophecy game, I venture to describe what I think I see.

> In the first place, tight money constraints no longer provide most utilities the option to build whatever will prove the most economical in the long term. There will be, of necessity, a continued trimming of programs to available financial resources. It is especially unfortunate that, unless there is federal help, there will be few conversions of oil-burning generating plants to coal-firing.

Utility executives are now far more aware of the risk factor. There is very little appetite among managers to bet the solvency of a company on a forecast of loads 10 or 15 years hence, which is the lead time for a nuclear plant. I do not foresee many new applications for nuclear licenses until licensing uncertainties are reduced and lead times are shortened, whatever the computer may say as to savings in the cost of generation on the assumption of trouble-free licensing and accurate forecasts of future conditions.

Many utilities have had a tiger by the tail in their need to complete plants which were started in the early 70's and are too far along in construction to be halted. However, in most cases, peak funding requirements will be over within 2 or 3 years. They will then be in position to reduce or avoid further stock dilution, and to tailor new investments to their means.

There will be increasing emphasis on ways of reducing the growth in peak loads, by programs of consumer conservation, and by load management by innovative rate designs, new categories of interruptible service, and other devices. Such activities are recognized by the utilities as being very much in their interest.

There will be more sales of interests in plants under construction to the unregulated sector, that is, the municipalities and cooperatives which enjoy subsidies and preferences of various kinds. These advantages make it possible for them to raise money more easily than the investor-owned systems, and they do not need to justify rate increases to regulatory agencies. Their money will be cheaper because they do not internalize the cost of government through taxes to nearly the same extent as the investor-owned systems. Such transfers will not serve the purpose of economic optimization, but they provide a wider financing base by drawing on the tax-exempt securities market.

There will be a gradual reduction of reserve margins through the 1980's. As you know, projections as to electric power needs in the 1990's vary widely. If the low estimates prove to be right, little harm will be done. If it should turn out that there are shortages, this country will be in a quandary. Its options will be either to build oil-fired plants with short lead times, or to suffer a ceiling on growth and employment. An unfortunate feature of the growth picture is that building for low growth, or rather failing to build for substantial growth, involves a sort of self-fulfilling prophecy. Industry will not build new manufacturing plants without assured power sources, and the inability of the electric power industry to build for the future with safe margins of reserve will inevitably affect the extent and location of manufacturing plant investments.

More generating capacity will be built by industrial users. Some will involve co-generation opportunities shared with the power companies and will reflect the economies of joing production of steam and electricity. In other cases, the industrial power plants will simply respond to the inability of industrial consumers to count upon central station service. Most industrial generating plants will probably be neither as economical nor as environmentally benign as the central stations they replace, but they will represent an investment in security.

I expect to see the electric utility industry pressing for release of legislative constraints which inhibit institutional improvements. In particular, they should have greater freedom to create joint agencies to finance generation and construction investments, and to seek third-party financing. They will be more interested in diversification opportunities, and should not be restrained from establishing free-standing enterprises in competitive areas.

This Committee has a special interest and responsibility for research -- more properly, the triad of Research, Development and Demonstration. The effect on RD&D of the prevailing regime of low earnings and high risks should therefore be mentioned. RD&D investments are risk capital, and the utilities will have smaller opportunities and incentives for such risk-taking. Demonstrations, which require hugh investments in the capital-intensive electric utility industry, are likely to be strongly affected. Moreover, technological progress is a feature of growth and earnings opportunities. The fifties and sixties, when capacity doubled in each decade, were characterized by enormous technological advances in power plant design. With slower growth there will be less interest by equipment manufacturers as well as utilities to invest in new technology, except for improvements to increase the efficiency, safety and reliability of existing equipment.

This bleak picture may improve. As I said, there are some self-correcting influences at work. For one thing, there is a wide-spread recognition that the licensing system for generating plants is wasteful, and a discredit to public administration in this country. There is no good reason why it should take twice as long to build a generating plant in this country as in Europe or Japan. There is a recognition that the uncertainties and delays introduced by the bewildering proliferation of federal and state licensing requirements for both nuclear and fossil plants imposes risks which no businessman should be asked to assume. The Congress is considering a rationalization of the licensing procedures of the Nuclear Regulatory Commission and the Environmental Protection Administration. Licensing reform would greatly reduce the cost of new capacity and would relieve to a considerable degree the need for rate increases.

There is some evidence that the utility commissions, state and federal, are beginning to face up to the twin facts, first, that their rate of return allowances have been too low to reflect the costs imposed by inflation and the licensing problems I have described, and, second, and more important, that the rate increases must parallel the allowed rates of return, which the commissions specify as the minimum return to which the utilities are entitled. Such recognition may be facilitated if the courts resume an active interest in determining whether commission-prescribed rates meet constitutional due process standards, a burden the courts have shown no anxiety to shoulder. At one time the courts were close overseers of the regulatory process, to a fault. Then, under United States Supreme Court leadership, they took the position that they would not review the details of regulatory rulings, but would look only to the overall result. The generality of this test has given it little vitality. The pendulum has swung so far that there is now little meaningful review of the regulatory product, but I hope the courts will soon recognize the need to provide direction to the utility commissions on their constitutional obligations.

Finally, the Federal Energy Regulatory Commission has recently instituted two proceedings which may turn out to have wide importence. One of them is a proceeding to develop a better method of determining rate of return. This proceeding is based upon a staff analysis which concluded that present procedures were inherently incapable of establishing rates of return which fulfilled the commission's responsibilities. The FERC Staff Report had the following to say on this subject:

> "In short, the Study Group concludes that Commission decisions on wholesale electric rates of return, as represented by the derived weighted averages, appear to have failed to reflect the realities of the marketplace.... Based on its review, the Study Group questions whether the Commission's legal and economic objectives can ever be realized in setting rates of return for the electric utility industry using current procedures and methodologies."*/

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*/ Discussion Paper on Electric Rate of Return prepared by an FERC Staff Study Group, dated December 15, 1980.

The other FERC proceeding, which is really a companion effort although not so identified, is an investigation into the financial health of the electric utilities. This is a long needed effort in a generic proceeding to look at the forest instead of the trees, and to determine what the present course of regulation has done to the financial fabric of the electric utilities and the impact on their ability to perform their functions.

Both the rate of return and financial health investigations are in early stages. If they are pursued to a conclusion, the results would affect directly only the wholesale business of the utilities, which accounts, on the average, for less than 10% of their revenues. The influence on the state commissions, which control the other 90%, could come only by force of example or intellectual contagion, barring an exercise of Federal jurisdiction over retail rates, which Congress has thus far studiously avoided.

I stress these small signs of regulatory improvement because regulatory failure is at the heart of the utility problem. It seems to me that before accepting the consequences of regulatory failure, and casting about for doubtful expedients to replace the pluralistic U.S. system of electricity supply, we should give more emphasis to finding cures for the faults of the regulatory process.

A number of scholars in recent years have proposed that the supply function of the electric utilities, that is to say, the generation end of the business, should be severed and deregulated. None of these studies, so far as I am aware, has attempted to take account of the special technological and institutional characteristics of the electric power industry. For my part, I do not see how forced divestment of generating plants would serve the interest of the consumers in this country.

One of the special institutional problems of this industry is that there is an important sector of the industry which pays little or no taxes, and which finances itself with municipal bonds on which the interest is also free from taxes. If there should be competition between these enterprises and the investor-owned companies, we should only learn what we can already guess, that it is cheaper not to pay taxes than to pay them. Municipal systems, moreover, tend to lean very heavily for their bulk power needs on federal power projects constructed with large taxpayer subsidies. The expansion of municipal power supply could only mean a massive transfer of power supply costs to federal taxpayers. The public systems enjoy a statutory preference to federal power supply, and unless the preference laws are changed, the new federal power sources would not be available for the benefit of the investor-owned companies and their consumers. This situation of inequality in the positions of the two competitive sectors does not exist, so far as I am aware, in any other industry. Addressing this problem seems to me a prerequisite to any sensible effort to introduce competition in the electric power industry.

Another special factor is the very nature of generating plant investments. Unlike planes and buses, they cannot be moved from one part of the country to another to follow the flow of business, but are built to serve a fixed market. The generating plants tend to be massive in size and involve individual investments which begin at $1 billion dollars. Under the best of circumstances, these plants take almost a decade to build. It seems obvious that no one will build such a plant, no one could borrow the money for such a plant, unless he has an obligation to serve, or unless he is protected by a cost-plus contract on a take-or-pay basis, or unless he has a protected market, or unless he is out of his mind. How bulk power supply competition would provide flexibility or reduce costs is, therefore, not apparent to me.

My own feeling is that the electric utility industry has done a better job than is generally recognized. The industry is taking the blame for costs beyond its control. The average consumer has no opportunity to compare his costs for most other services and commodities on a regular monthly basis, but he pays for his electric service, not as he uses it, day-by-day, but a month at a time. It is a question of confusing the messenger and the message. The consumer would hardly credit the statement, which is amply supported by the data I have given you, that he is in fact enjoying a subsidy provided by the people who put up the money for the facilities which serve him.

The electric utilities through the years have provided a high quality of service and a high degree of reliability and assurance of future adequacy of supply. They have raised vast amounts of money on the capital markets at low cost. They have developed a special management philosophy in which the requirements for service equal in importance, and indeed have been paramount, to the financial interests of their investors. All this rested on the integrity of a compact under which regulation by public agencies, monitored by an independent judiciary, assured them a reasonable return. To my mind, the future which would be in the greatest interest of the American public would be to restore the integrity of this compact, at the same time that steps are taken to reduce construction costs by improvements in the licensing process and by permitting greater institutional flexibility. There is still a possibility that most of the benefits of this superior institutional arrangement can be preserved. The alternative, I believe, would result in higher real costs, in greater burdens on the federal treasury, and in major uncertainties as to adequacy of future electric power supply.

If there are any questions, I shall try to answer them.

Mr. FUQUA. Thank you, Mr. Swidler.

Mr. Nichols.

[The biographical sketch of Mr. Nichols follows:]

Guy W. Nichols

Chairman, President and Chief Executive Officer

New England Electric System

Utility executive; born Colchester, Vt., October 27, 1925; son of Guy W. and Gladys (Thomlinson) Nichols; B.C.E., University of Vermont, 1947; M.S. in Business Administration, Sloan Fellow, Massachusetts Institute of Technology, 1961.

Married Shirley Hibbard, June 21, 1947; children, Pamela, Gail, Sally.

With New England Electric System, Westborough, Massachusetts, 1947; Executive Vice President, 1968-70; Director, 1968; President, 1970; Chief Executive Officer, 1972; Chairman, 1978; Chairman and Director, New England Power Company, New England Power Service Company, New England Energy Inc., Yankee Atomic Electric Company; Director, Massachusetts Electric Company, Narragansett Electric Company, Maine Yankee Atomic Power Company, Vermont Yankee Nuclear Power Corporation, Breeder Reactor Corporation, Electric Power Research Institute, First National Bank of Boston, Nashua Corporation, State Mutual Life Assurance Company of America.

Member of International Energy Agency Coal Industry Advisory Board. Chairman of Management Committee, New England Power Pool. Trustee Thomas Alva Edison Foundation. Member of the Corporation, Woods Hole Oceanographic Institution. Member of Corporation Development Committee, Energy Laboratory Advisory Board, Massachusetts Institute of Technology.

Served with the United States Army, 1944-46. Home: 69 Wildwood Drive, Needham, Ma. 02192. Office: 25 Research Drive, Westborough, Ma. 01581.

4/10/81

STATEMENT OF GUY NICHOLS, CHIEF EXECUTIVE OFFICER, NEW ENGLAND ELECTRIC SYSTEM, WESTBOROUGH, MASS.

Mr. NICHOLS. Thank you, Mr. Chairman, members of the committee.

Mr. FUQUA. Let me say that all the statements that are submitted will be made part of the record, and if you want to summarize your full statement, it will be part of the record.

Mr. NICHOLS. I certainly will summarize, if I may.

I am the chairman of a utility holding company that serves roughly 1 million electric customers in New England, including much of the States of Rhode Island, Massachusetts, and parts of New Hampshire and, as such, I represent an industry that Joe has just described as being in deep financial trouble. We are no exception. We may not be quite as ill as some of the other companies, but we still have major financial problems, and over the last few years, in an attempt to solve those earning problems, we have moved away from being a straight utility company.

As we have moved away from a straight utility company, we obviously have done it in an attempt to solve some of our own problems and bootstrap our earnings upward.

It might be helpful if I described some of our efforts of the past few years.

Our first venture into diversification was launched in the winter of 1974, the winter of the OPEC embargo. Our customers were very rightly upset by the high-cost of fuel, particularly the high-cost of fuel that was contained in their electric bill, and they were putting great pressure on the regulators to do something about the fuel clause portions of their electric bills.

We realized as an industry that we needed the financial protection of those fuel clauses, and we needed to prove to our regulators that we were doing everything possible to keep our oil costs to a minimum.

This started us thinking about oil and gas exploration and development as one way to prove to our regulators that we were doing everything we could. So we started down that road in 1974, and in the first year we put about $5 million into oil and gas exploration. This has moved on up, and this year, we're putting about $100 million into oil and gas exploration.

We have been lucky in this venture. We have been helped by a lot of things. We have been helped by OPEC pricing, and we have been helped by having some very good oil and gas partners. We have been helped by partial deregulation. In total, both our customers and our investors have benefited from this venture.

Our next venture was into the shipping business, and this is one we just started last year. We followed the same approach we used for oil and gas. We decided to get a knowledgeable partner who was in the business and then structure a deal, so that if the partner made money we made money; if the partner lost, we lost. For example, we are building the first coal-fired coal ship. This is a picture of it. This ship will be the first of its kind built in over 25 years. It will carry domestic coal and it will burn domestic coal. It is being built in New England and it will serve New Englanders and will serve them well. We are now thinking about a second ship.

But this diversification program of ours is just part of an overall program that we launched in 1979, in an attempt to get back in step with our customers. It's all too easy for a utility today to be in the mode of confrontation. We are very aware of how easy it is for us to get into that mode. We try to buy a property for a future generating site and people oppose it; we try to build a transmission line and others oppose it; we go for a rate increase, some oppose it.

We have to get out of that lockstep of confrontation, and so we decided we needed to know what our customers wanted from their electrical utility. We found they wanted their electric utilities to keep their costs down, and they wanted us to get off foreign oil. These became the two main objectives of our program. We have five individual programs that support these objectives. [Chart 2.]

These five programs are cornerstoned around a load management and conservation effort that Mr. Swidler just described so aptly. We realize that every new unit of generation that we bring on line in the years ahead will undoubtedly come on line at a higher cost than the average cost we are then charging our customers. Therefore, it will raise the average cost and naturally our customers don't like this.

Load management and conservation are the keystone program. If I can have the next chart. [Chart 3.]

This is just a few of the activities that we have under way in the loads management and conservation effort.

Next chart, please. [Chart 4.]

One of the programs that has gotten a great deal of publicity is our coal conversion program. It is well under way. It is a successful program. We are already burning coal, and last month we were very happy that we had the lowest fuel clauses in southern New England, and largely because of our coal conversion program. We have more work going on in this area.

Next chart. [Chart 5.]

And as this chart shows, we were 78 percent dependent on oil in 1979. By the end of this year, we will be down to less than 30 percent dependent on oil. By 1985 we will be less than 10 percent dependent on foreign oil and still going down. I hope we go negative before the end of the decade, and I think there is a chance that we will. It's going to take a lot of work and luck. [Chart 6.]

Our third program is listed on the lower chart. It is the expansion of the oil and gas program that I have already described, and I will not go further into that program.

Our fourth program is one that may be of particular interest to this group, because it involves the development of what was originally scheduled to be 100 megawatts of alternate energy resources. We have already revised that figure upward to 200 megawatts. That's a lot for a system of our size, but we think we will make the new target. I think it might be of interest to this committee to know that we are already successful in this area. There is tremendous interest. Perhaps it's not all currently economical, but we are learning a lot, and I think a lot of this is of value from an R. & D. viewpoint. [Chart 7.]

The fifth and final program involves new businesses, and now we get back to diversification. This chart lists some of the businesses that I have already touched on. I mentioned the first two. We also operate a service company. we have about 250 engineers and about 400 people in construction. We do a lot of work for other utilities.

Believe it or not, we also operate an energy institute. I never thought we could make money out of it, but we are making a little.

We have developed a business that came out of our own R. & D. activities and, by the way, our budget for R. & D. is about $5 million this year. We have developed a two-way automated communications systems called TWACS that permits us to communicate over our own electric lines to our customers' electric meters and electric loads.

This particular development, we think, is essential to tomorrow's load management activity for our industry. TWACS has been licensed by Emerson Electric in St. Louis. They now have two major test installations underway, one in Missouri and one in Massachusetts. We are not yet sure it's economical, but we think it has a chance. And we have some other business ventures coming down the line. [Chart 8.]

The main reason for us to diversify obviously has been the need to upgrade our earnings. By upgrading our earnings, we hope to move our marketplace price up to the point where it is at or above book value. This is critical to a regulated utility whose future earnings are a function of book value. If we have to sell stock below book value, we dilute those future earnings.

It is critical that as an industry we pull ourselves up above that magic line. It gives us better access to capital. It also helps us to attract good people. One of the management challenges of running a low-growth or no-growth industry is, how do you keep good people at the same time you're trying to discourage growth?

Well, it's not easy. And diversification is one area that will permit us to do this job.

With your permission, I will not go through my other charts that involve deregulation of our industry. I would like to just summarize my comments in that area to say that total deregulation is something that, as a businessman, I would heartily favor, for I would be competing with yesterday's low-cost plants built with yesterday's dollars and against newcomers coming in at today's high plant costs and today's big dollar costs.

But I don't think many of the people suggesting deregulation are talking about total deregulation. They are talking about partial deregulation, and if we are forced in some sort of partial deregulation, I hope we will first give it careful study, because there are a lot of potential problems to tomorrow's customers. If we do move in that direction, I would argue we need to do it in evenhanded fashion. Let's make sure the grounds are the same for all comers, for the big and for the small, for the utilities and the nonutilities. [Chart 10.]

I know you are aware that some of the ground rules that were established in the Energy Act of 1978 do not allow the electric utility to participate in certain ventures. I think this is unfair and not in the best interest of our customers. We in our industry, I am sure, are willing to compete, but what we don't like to do is compete in a fight where we've got one hand tied behind our back and an anchor tied to each leg. That is the situation today.

Mr. Chairman, gentlemen, I thank you for a chance to talk to you this morning.

[The prepared statement of Mr. Nichols follows:]

STATEMENT OF GUY W. NICHOLS
BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS
JUNE 24, 1981

My name is Guy W. Nichols. I am Chairman and Chief Executive Officer of New England Electric System, an investor-owned public utility holding company. Its subsidiaries serve approximately one million retail electric customers in Massachusetts, Rhode Island, and New Hampshire. I appreciate the opportunity to participate in the Subcommittee's hearing on the Future of the Nation's Energy Utilities. This topic is naturally of paramount importance to New England Electric, and I commend the Subcommittee for recognizing the ramifications of the industry's poor health and conducting this hearing.

My remarks will focus upon the direction in which I believe the electric utility industry and those responsible for its regulation must turn in the best interests of consumers, the investing public and the nation as a whole.

As an industry, we are a diverse group. While many problems are common, including the very difficult one of maintaining financial stability, many others vary significantly from region to region across the country. Similarly, some opportunities are available throughout the industry, but others exist only in certain areas.

Other speakers are addressing the degree of the financial illness plaguing our industry. I would like to comment briefly on its cause and then on some of the things we are doing to try and bootstrap ourselves back into better shape.

Why is our industry in such deep financial trouble? The answer is, I believe, the inability of the regulatory system to cope with the inflation we have experienced and are continuing to experience. This has resulted in poor earnings and a drop in the market price of utility shares. This combination has led many utility companies to look for other business opportunities as a possible (not guaranteed but possible) way of achieving a fair return for their investors.

Our System is an example. We have moved away from being a straight electric utility to become an energy company with interests in oil and gas, shipping and other areas. Our management group believes in diversification, and we have moved significantly in this direction in the past seven years.

Our first new venture was launched in early 1974, for two reasons.

I'm sure you recall the winter of 1973 - 1974; the time of the OPEC oil embargo. Our customers saw the fuel cost portion of their electric bills more than triple within a few month's time. They were understandably upset, and put great pressure on our regulators to do something about the fuel clause portion of their electric bills.

We knew that we had to prove to those regulators that we were doing everything possible to keep our fuel coststo a minimum. Only in this way could we have reasonable assurance that they would continue to give us the protection provided by automatic fuel clause adjustments incorporated in our customers' monthly bills.

We decided that one way to help keep fuel cost to a minimum, and prove to our regulators that we were doing everything possible, was to actually get into the business of exploring for oil and gas. We realized there were risks in the oil and gas business, but we also knew there was the potential to find and control primary energy resources that would be increasingly valuable in the years ahead.

Unfortunately, a public utility holding company such as ours does not have the luxury of making a unilateral business judgment of this type. It must first receive the approval of the Securities and Exchange Commission. We obtained that approval, but paid a significant price. The SEC's permission to go into the oil and gas exploration business was conditional; it limited the venture's earnings to what is called a full utility rate of return, (the latest return allowed by FERC on our inter-company transactions.) But, I really do not think this approach provides fair compensation to our investors, compared with the unlimited returns obtainable by investors in similar ventures that don't happen to be owned by a utility. But, we went forward on this basis, and have been relatively lucky.

So, keeping our fuel cost to a minimum and proving to our regulators that we were accomplishing that objective, was one of our two major reasons for diversifying into oil and gas. The other, of course, is that we did see a good business opportunity and a chance to improve earnings. We decided that even if we were limited to a full utility rate of return on these investments (at least until we could convince the SEC to change its mind), it would be better than the less than full return we were earning on our regular utility rate base.

So oil and gas started us down the diversification road. The first year we spent five million dollars on the venture. Last year we spent about sixty million dollars, and this year our budget for the venture is at the one hundred million dollar level.

The combination of careful selection of a first class venture partner, OPEC pricing pressures, oil deregulation, and some movement toward the marketplace pricing of natural gas, has helped make our oil and gas exploration activity a sound operation. Our customers are benefiting, and our investors receive a full utility return on the dollars they put into this part of our operation.

Next came shipping. In 1980 we decided to get into the shipping business. We followed the approach that had proven successful with oil and gas. We found a knowledgeable partner that was already operating successfully in the business, and structured a deal that permits him to run the venture under an arrangement that keys our success to his.

Together we are building the first coal-fired, coal-carrying ship built in this country in over twenty-five years. This ship is being built in our service territory in Quincy, Massachusetts, and it will both use and carry U.S. coal for the benefit of our customers.

"See picture"

The ship is now being designed; the keel will be laid this fall and launching is planned for early 1983. We are now considering a second ship.

Our diversification program is an integral part of our System's long range plan which we call NEESPLAN. I have included with my written testimony a copy of the Executive Summary of NEESPLAN issued in 1979 together with the update issued last fall.

NEESPLAN is an effort to get our System companies back in step with our customers. It is all too easy, with confrontation so fashionable in today's world, for an electric utility to always find itself in an adversary role as regards its customers.

The utility applies for a rate increase; its customers oppose. The utility tries to build a new generating station; some of its customers oppose. The utility wants to build a new transmission line; various customers are always there in opposition.

The media play up these confrontations, and pretty soon most customers think the utility does nothing but fight. We realized that somehow we had to get out of this seeming mode of confrontation and into step with our customers.

It didn't take much insight on our part to see that our customers' two principal concerns about their electric supply in New England were cost and overdependence on foreign oil.

We keyed our planning effort on those two concerns.

[Chart 1]

To accomplish our fundamental objectives of minimizing both the cost of our product and our utilization of foreign oil, we developed five programs.

[Chart 2]

The number one program -- we call it our CORNERSTONE Program -- is our load management and conservation effort. We know that each new increment of generation that we bring on line will be more expensive than the average cost of our existing generation. This means that each time a new unit is built, our customers' payments for an average kilowatthour will increase.

Through intensive load management and conservation programs, we are doing our level best to insure that we avoid building additional generation. Some of these programs are shown on this chart.

[Chart 3]

Our second NEESPLAN program -- Coal Conversion -- has received a lot of publicity, because it has proven to be a very successful way of accomplishing the two basic NEESPLAN objectives: getting our customers' cost down and reducing our reliance on foreign oil. This chart, chart # 4, shows our conversion plan.

As recently as 1979, we were nearly 80% dependent on foreign oil. As this chart, chart # 5, indicates, by the end of this year, we will be less than 30% reliant on foreign oil. By 1985, with a little luck and a lot of hard work, we will have less than 10% foreign oil in our fuel mix. The bulk of this reduction is attributable to coal conversion.

Our third program is the expansion of our oil and gas venture that I have already described.

The fourth NEESPLAN program calls for us to obtain 200 MW of generation from alternate and renewable resources. These are the only additional generating commitments we hope to make for capacity due on line in this century. Our original and updated objectives in this area are described on this chart, chart #6.

This program will help assure that research and development work essential to giving alternates a chance will be done. We expect most of this new generation actually will be built by others, and thus we will avoid having to finance it.

The fifth and final NEESPLAN, program involves New Businesses.

[Chart 7]

As this chart indicates, in addition to being in oil and gas, and in shipping, we are also supplying engineering and construction services, and we run an Energy Institute. TWACS is an acronym for our two-way automative communication system, a system that transmits and receives signals, over our own electric lines, to our customers' meters and to their controllable electric equipment. We developed this system, patented it and have licensed it to Emerson Electric. We think it has great potential. We have more ventures in the works.

This next chart suggests some of the more compelling reasons for us to move into these new businesses.

[Chart 8]

The principal one, in my mind, is the chance to improve earnings.

As I mentioned earlier, the regulatory process has failed to cope with the problems created by continued inflation. Some valiant attempts have been made. But the end result is still a financially ailing industry. As a nation, we have expropriated large amounts of capital from the investors in the electric utility industry and used that capital to subsidize the electric customers of this country. Because this is well recognized by the investment community, the market price of utility shares has fallen way below book value.

The financial weakness of utilities today will have a devastating effect on tomorrow's electric customers. Despite conservation efforts, the demand for electricity is continuing to grow. Utilities have a public service obligation to meet the increased demand by consumers. The industry must raise new capital for this purpose, including new equity capital.

But, every time a utility sells new shares at a price below average book value, it reduces the earnings potential of existing shareholders. That is why, virtually without exception, electric companies are doing their utmost in the areas of load management and conservation to assure that construction programs are kept to the absolute minimum, consistent with meeting tomorrow's electric needs and reducing our reliance on foreign oil.

But getting back to this chart, through diversification we have the potential to upgrade our earnings - and, through improved earnings and recognition by the investment community that we have profitable unregulated subsidiaries, we make our stock more attractive to investors, and we will increase the market price of our shares, hopefully to a price above book value.

Another advantage to diversification lies in the area of management capabilities. It is difficult to attract and hold topnotch people while operating an organization that is doing its utmost not to grow. Managing a no-growth industry during a period of inflation is a real challenge, but we have found that the added challenges of our diversified businesses help us to attract and retain good people. This is important, and it is a significant ancillary benefit of our System's diversification program.

But now let's address the question "Why deregulate?"

[Chart 9]

As this chart indicates, deregulation is in the air. Along with supply-side economics, it is one of the more popular topics of conversation as economists and para-economists talk about our troubled industry.

Why? Well,deregulation may work better. Today's methods of regulation are not working well.

In addition, "deregulation" is in the eye of the beholder; it means many different things to many different people. To some, it means total deregulation.

Total deregulation is something that, as a businessman, I wholeheartedly favor. With it, I will happily and easily improve the lot of the investor in our securities.

Our power plants, built at yesterday's lower construction costs, and financed largely with yesterday's cost of debt and preferred equity, will beat the pants off the prices charged by any newcomer that should venture into the field on a fully competitive basis.

I harbor no illusions that complete deregulation of electric energy is in the cards. And frankly, I can't recommend it to you.

Most economists, when discussing deregulation, have in mind some form of partial deregulation, usually in the area of new generation. Unfortunately, this brings with it a host of problems, just a few of which are listed on the next chart. I am sure there are many more.

[Chart 10]

If this nation does move in the direction of deregulation of electric supplies, I only hope that we will first give it a great deal of careful study. These are significant problems, and I expect their solution may be far more expensive than solutions to our current regulatory problems.

But, if we do move toward deregulation, I hope we do it evenhandedly. Let's make sure that the ground rules that will apply to builders of tomorrow's generation and transmission are the same for all comers.

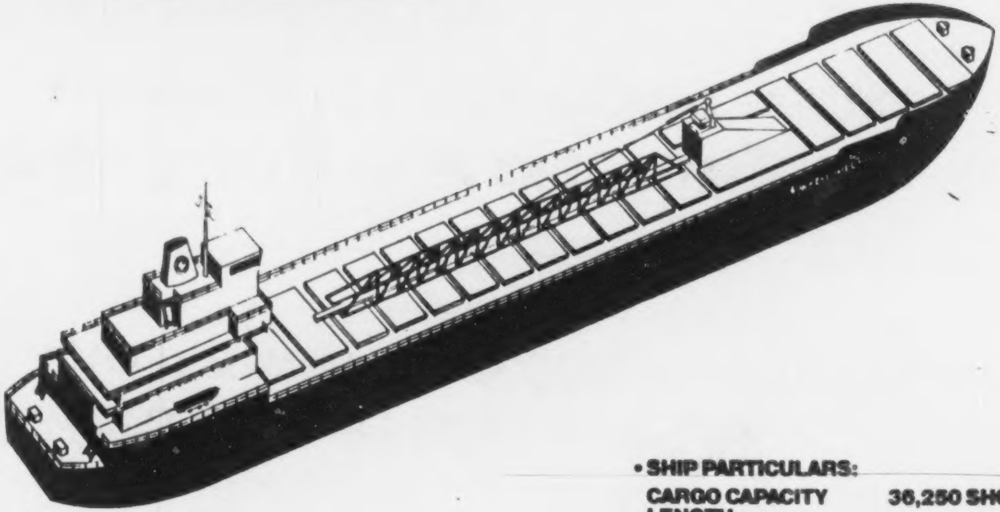
As I expect you are aware, some of the ground rules built into the Energy Act of 1978 prevent an electric utility from participating on an evenhanded basis with new, non-utility entrants into the field. I believe this approach is both unfair and not in the best interests of tomorrow's customers.

We in our industry are happily willing to compete. What we don't like are laws that force us to compete with one hand tied behind our back and an anchor attached firmly to each leg.

Thank you for the opportunity to speak to your Committee this morning. I will be happy to answer any questions concerning my remarks.

New England Electric's COAL-FIRED COAL SHIP

To be built by NEW ENGLANDERS
for NEW ENGLANDERS



- **SHIP PARTICULARS:**

CARGO CAPACITY	36,250 SHORT TONS
LENGTH	655 FEET
BEAM	95 FEET
DEPTH	55 FEET
DRAFT, LOADED	32 FEET
FUEL	COAL or OIL
CRUISING SPEED	15 KNOTS
CREW	25
CARGO DISCHARGE RATE	3500 TONS/HR

NEESPLAN

First issued late in 1979,
the overall objectives remain...

- To keep our customers energy costs down and...
- To reduce our dependence on foreign oil

CHART 1

NEESPLAN

Five basic programs were established...

1. Conservation and Load Management
2. Coal Conversion
3. Domestic Oil and Gas
4. Alternate Energy Sources
5. New Business Opportunities

CHART 2

NEESPLAN -1st UPDATE

Strategies...

CONSERVATION

Residential Audits
Conservation Rates
C and I Audits
Public Education

Conservation Devices
- Wind machines
- Solar
- Insulation
- Efficient appliances
- Heat pumps et. al

LOAD MANAGEMENT

Storage Heating
Storage Water Heating
Air Conditioner Cycling
Storage Cooling

Load Management Rate
- Time of use
- Peak control
- Interruptible

TWACS
Demand Control For :
- Solar back·up
- Co·generation back·up
- Heat pump back·up

CHART 3

NEESPLAN -1st UPDATE

Coal Conversion

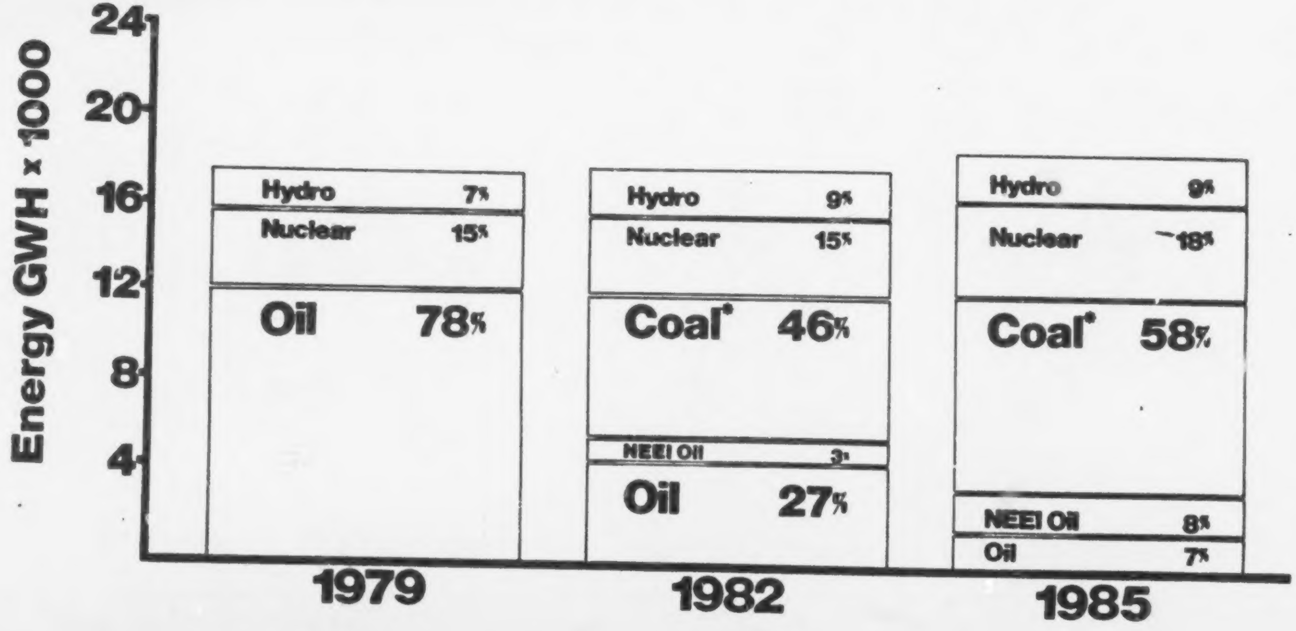
	CAPACITY MW	AVERAGE ANNUAL OIL CONSUMPTION (bbl) (in thousands)
Brayton 3 Units	1,164	11,600
Salem Harbor 3 Units	318	3,100
South St. 2 Units	103	1,000
Total Co. Units	1,585	15,700
***Mt. Tom**	56	400
Total	1,641	16,100

* INCLUDES 38 SHARE UNDER "LIFE OF UNIT" CONTRACT

CHART 4

New England Electric Converts to Coal

NEES Energy Mix



*Will be capable of switching back to oil quickly

CHART 5

NEESPLAN

ALTERNATE ENERGY SOURCES

Original Objectives

1. Secure 600,000 MWH per year from alternate energy sources by 1995
2. Secure 100MW of generation from alternates:

Small Hydro	30MW
Solid Waste	50MW
Wood	15MW
Misc.	5MW
Total	100MW

Updated Objectives

1. Secure 1,000,000 MWH per year from alternate energy sources by 1996
2. Secure 200MW of generation from alternates:

Small Hydro	30MW
Solid Waste	90MW
Wood	20MW
Wind	10MW
Unspecified	50MW
Total	200MW

CHART 6

N.E.E.S. DIVERSIFYS

Oil _and_ Gas Exploration Development

Shipping

Engineering _and_ Construction

Energy Institute

TWACS

?

CHART 7

WHY DIVERSIFY?

HOPE TO IMPROVE:

Earnings

Market Price

Access to Capital

Management Capabilities

And ?

CHART 8

WHY DEREGULATE?

(a) It's in the "AIR"

(b) It may work better:

- sick industry
- capital crunch
- airlines example

(c) It's not defined

(d) The grass is always "GREENER"

CHART 9

A FEW DEREGULATION PROBLEMS

(a) Sub Optimization of MIX

(b) Questionable Assurance:
  - Tomorrow's Generation
  - Tomorrow's Transmission

(c) Cream Skimming

(d) ?

CHART 10

NEESPLAN

1980 - 1995

INTRODUCTION AND EXECUTIVE SUMMARY

October 1979

NEESPLAN is a long-range corporate plan developed by and for the New England Electric System companies.

New England Electric System is a public utility holding company registered under the Public Utility Holding Company Act of 1935. New England Electric System itself does no public utility business, but owns 100% of the common stock of four electric utility operating subsidiaries: Granite State Electric Company (Granite), Massachusetts Electric Company (Mass. Electric), The Narragansett Electric Company (Narragansett), and New England Power Company (NEP). In addition, New England Electric System has two other wholly owned subsidiaries: New England Power Service Company (NEPSCo), a subsidiary service company, and New England Energy Incorporated (NEEI), a fuel subsidiary. The subsidiaries of New England Electric System are collectively referred to herein as "New England Electric," "the System," "NEES," or the "NEES System." NEES System headquarters are located at 25 Research Drive, Westborough, Massachusetts 01581, telephone number 617/366-9011.

The name "New England Electric System" means the trustee or trustees for the time being (as trustee or trustees but not personally) under an agreement and declaration of trust dated January 2, 1926, as amended, which is hereby referred to, and a copy of which as amended has been filed with the Secretary of the Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of New England Electric System binds only its trust estate, and no shareholder, director, trustee, officer or agent thereof assumes or shall be held to any liability therefor.

INTRODUCTION

NEESPLAN is one energy system's approach to planning for the 1980's and 1990's. It is based on an intensive conservation and load management program designed to limit the growth in demand for electric energy to the minimum consistent with a strong regional economy.

NEESPLAN varies significantly from the traditional approach to the energy planning process which consists of projecting the most likely natural growth in demand for electricity and attempting to build new generating capacity to meet this estimate.

The genesis of this departure from tradition lies in these simple facts. Prior to 1970, electric utilities comprised a declining cost industry in which every new unit of electricity produced cost less than the last. Under this circumstance, unlimited, natural growth in the use of electric energy was beneficial to both the producer and to all consumers, since even consumers needing no additional energy benefited from rate decreases.

However, in recent years, the benefits of new technology and the economies of scale achieved with the construction of new generating facilities have been more than offset by the impact of inflation, oil price increases and increased construction costs associated with environmental and safety concerns. The cost to produce electricity began to rise at the turn of this decade and, with the oil embargo of 1973-1974 adding its impetus, has accelerated rapidly.

Under this set of circumstances, unlimited growth in the demand for electricity benefits neither the producer nor the consumer. Producers are forced to add extremely expensive new generating capacity at great financial risk, and consumers are faced with continually rising energy prices.

To bring this spiral under control requires a new approach -- an approach that combines the best efforts of consumer and producer to control and limit the growth in energy demand to a level that best meets the needs of consumers and investors alike.

NEESPLAN maps out this new approach over a fifteen-year period. The plan is not frozen. It is flexible so that it can adapt to rapidly changing events in the world of energy.

NEESPLAN is not a "big brother" approach. The conservation measures it incorporates will only work with the cooperation of customers. Neither does NEESPLAN avoid the necessity of building some new generating capacity.

Finally, NEESPLAN does not stray from the basic mission of an electric utility: to provide a reliable supply of electric energy at reasonable cost, to provide an adequate return to the investor and to accomplish these tasks in an environmentally acceptable manner. Simply put, NEESPLAN is a new way to accomplish an old job.

The NEESPLAN approach to planning will be considered controversial by many, and events may prove that the traditional approach to planning is still best. But, our analysis of the forces affecting world energy supplies has us convinced that we need to embark on this new path.

I. Executive Summary

NEESPLAN addresses the energy needs of our customers from 1980 to 1995. The plan establishes three key goals for the next 15 years:

A. A major conservation and load management program designed to reduce our average annual peak load growth to 1.9 percent, thereby reducing substantially our need for additional, new generating capacity;

B. The conversion to coal of half of our present oil-fired capacity; and

C. A reduction in our use of foreign oil from the present 73 percent to no more than 10 percent of our energy needs.

A vigorous conservation and load management program is critical to the success of NEESPLAN. If we achieve our conservation and load management objectives, we can limit new generating requirements to about 200 MW in addition to our existing capacity entitlements in the Seabrook, Pilgrim and Millstone nuclear projects. To meet these needs, we will build or buy 100 MW of alternate energy sources and acquire 100 MW of additional nuclear or other base-load capacity.

With this new capacity, coal conversion, and an expanded domestic oil and gas exploration program, we can reduce our dependence on foreign oil to 10 percent of our energy needs and save our customers an estimated $1.2 billion over the next 15 years.

Conservation and Load Management

NEESPLAN addresses the issue of planning electric generating capacity from a new angle. It sets an ambitiously low growth target, namely, 1.9 percent per year for peak demand and an average annual growth in energy use of 2.4 percent. A far-reaching conservation and load management program is key to our efforts.

By meeting these goals, we can use existing generating capacity more efficiently (raising our annual load factor from the expected 59 percent to 66 percent); delay the construction of future, large, new generating facilities; and slow the upward trend in electric rates.

We are proposing to work very closely with our customers to develop conservation and load management programs, acceptable to them. Only in this way can we achieve our long-term goal of reduced growth in load and electricity consumption.

We will offer to visit every residential, commercial and industrial customer in our service territory. During the visit, we will audit their home or business for energy savings and help them determine their total energy needs. We will offer to expedite their efforts to save energy with insulation and efficient appliances and equipment. Together with our customers, we will work to achieve our goal of limiting the growth in electric energy (kilowatthour) usage to 2.4 percent per year.

However, reduction in usage is not enough. Our generation needs are determined by the number of kilowatts our customers demand at any point in time. Reduced usage and more efficient equipment are not enough to reach our goal.

To encourage shifts of electricity use from peak periods of demand to off-peak periods, we will provide new rate incentives. We will also institute special rates for customers who substitute heat storage devices for uncontrolled electric resistance space and water heating. Our customers, if provided with acceptable signals, can help to manage their own electric load.

In addition, we anticipate the need for an automatic load control system to read customer meters at various times during the day. This system should also be capable of turning off and on selected customer loads. We have developed and patented a system of this kind -- TWACS (Two-Way Automatic Communication System). We are now testing it in our Massachusetts service area.

An additional element of the NEESPLAN conservation and load management program involves solar applications and cogeneration. We will continue to work with those customers interested in utilizing these two energy resources, both of which can help us attain our conservation and load management goals.

Implementation of a strong conservation and load management effort has begun. We have already provided our customers with conservation information, off-peak rates and off-peak water heaters. We have served heat storage systems, tested solar water heaters, installed time-of-use meters and encouraged cogeneration. Under our plan, these programs will be expanded.

With our load management plan, we hope to reduce both our winter and summer peaks by over 500 MW by 1995. If we meet our conservation goals, we will reduce each of these peaks by another 300 MW. We anticipate saving some 1,600,000 MWH of energy per year by 1995. If fueled by oil, this is the equivalent of 2.6 million barrels per year -- enough to drive 76,000 cars an average of 15,000 miles per year at an average consumption rate of 15 miles per gallon.

Diversification of Energy Mix

A diverse energy mix is a fundamental NEESPLAN objective. Right now, 78 percent of New England Electric's electric sales are generated with oil. We burn over 21 million barrels of oil a year. Nearly all of that is imported.

The problems with oil are known too well -- cartel-controlled prices and supplies dependent on fragile governments. But, other energy sources are also subject to disruption. In 1977, a prolonged coal strike created a severe emergency in the midwest; nuclear plants are subject to changing regulatory requirements; and, as recently as the winter of 1976-77, thousands of workers were laid off because of natural gas shortages.

Thus, we see the need to diversify our energy sources as we reduce our dependence on foreign oil.

Success in implementing our conservation and load management, new generating capacity, coal conversion and domestic fuel supply programs will dramatically improve New England Electric's ability to meet the energy needs of its customers.

By 1995, NEESPLAN calls for an energy mix consisting of 39 percent coal, 25 percent nuclear, 18 percent domestic oil, 10 percent foreign oil, and 8 percent hydro and alternates. This mix would eliminate overdependence on any one energy resource and reduce our reliance on foreign oil, to a realistic minimum. This mix would also provide great flexibility to adjust to changes in resource supply.

Coal Conversion

The major step in achieving a diverse energy mix is coal conversion. To solve the immediate crisis in oil supply and cost, we are converting three of our largest fossil-fired units to coal. By the end of 1981, some 1170 MW of generating capacity at our Brayton Point generating station will be fired with coal. Under our plan, three more units at Salem Harbor -- an additional 318 MW -- will be converted by 1983, if economically and environmentally feasible. As a result, our oil requirements will be reduced to 11 million barrels by 1995 -- half of what we are using today.

Reduction of Dependence on Foreign Oil

By 1995, our goal is to reduce our dependence on foreign oil from the current 73 percent of our energy needs to no more than 10 percent. We now burn 21 million barrels of oil. If we did not diversify our generation mix, we would have to burn 33 million barrels per year by 1995. Coal conversion will cut this number to 18. Increased nuclear, hydro and alternates will contribute 7. Thus, in 1995, we will be burning only 11 million barrels of oil.

To meet the NEESPLAN goal, we need to supply at least 7 of this 11 from domestic sources. We will increase our oil and gas exploration program to provide this quantity.

After the 1974 oil embargo, we created New England Energy Incorporated (NEEI) to find and develop our own oil supplies. It has succeeded. Production started in 1978 and has already saved our customers money. We estimate that in 1980 we can produce the equivalent of about two million barrels of oil from the natural gas and oil reserves that we have already discovered.

We designed this program to produce the equivalent of four million barrels of oil by the late 1980's. Under NEESPLAN, these efforts will be nearly doubled.

In the past, NEEI has worked with an experienced gas and oil exploration partner to achieve its goals. We will use the same strategy to meet the NEESPLAN target of seven million barrels.

New Capacity

Our present nuclear commitments in Seabrook 1 and 2, Millstone 3, and Pilgrim 2 will provide about 500 MW. To meet our needs for base-load capacity beyond these commitments, we should add 200 MW. We plan to buy or build half of this amount from conventional domestic sources. The other 100 MW is planned to come from alternate energy sources.

Several conventional options are open. We can buy additional capacity in nuclear units now under construction. New base-load Canadian hydro capacity may also be available. But, we already purchase 90 MW of capacity from Canada, and we must avoid over-reliance on foreign sources, even when we import from a good neighbor like Canada.

We also plan for 100 MW of new capacity from alternate energy sources. NEESPLAN calls for an estimated 30 MW from low-head hydro, 50 MW from solid waste, 15 MW from wood, and the remaining 5 MW from a combination of small demonstration projects, including a wind generation project.

To meet our alternate energy source goals, we will follow two paths. We will build and operate some capacity and will purchase the energy output from some capacity developed by others.

Financial Considerations

NEESPLAN should reduce capital requirements over the planning period from $6.6 billion to $5.1 billion, a reduction of 22 percent.

With NEESPLAN, we estimate costs of $192 million for coal conversion, $638 million for additional fuel exploration, $335 million for load management, conservation and alternate energy sources, and $127 million for conventional sources.

A substantial portion of the required capital will be produced internally. However, some outside, permanent financing will be necessary, especially over the next five years. Under NEESPLAN, we will reduce outside financing to very modest levels after 1985.

NEESPLAN has the potential to significantly improve our investors' earnings over the next 15 years. Regulatory agencies here in New England and in Washington are fully aware of the need for energy conservation, load management, secure energy resources, and coal conversion.

By limiting electric growth, we will avoid building additional generation in the latter half of our planning cycle.

As a result, we will need less rate relief than would be required with a higher, uncontrolled growth rate. However, some additional capital will be needed in the early years to produce immediate fuel savings and adequate energy for our customers and to implement our conservation and load management program.

These early year costs present a challenge to our regulators as well as to us. Will the regulators consider our rate requirements using historic test year data that fail to consider the inroads of inflation and the NEESPLAN costs described herein? If so, our investors would be inadequately compensated for the risks they will take.

During these early years, we must work closely with our regulatory agencies as we initiate these programs. We will need to incorporate these expenses in "forward-looking test year" rate applications to insure fair treatment for our investors. Conservation efforts must not be penalized.

We are confident our regulators will recognize the great potential for customer savings under NEESPLAN and make explicit allowances in our rate cases to assure our investors receive fair treatment.

New Business

Opportunity and necessity are the key elements in NEESPLAN's approach to new business.

The world's energy problems present major challenges but also create great opportunities. NEESPLAN calls for further involvement in energy areas related to our basic business of supplying electric service.

Two such areas are: further investment in domestic oil and gas exploration activities and implementation of our own two-way automatic communication system (TWACS) with Emerson Electric. We think this system, which uses electric lines to transmit load signals and to read meters, is the best automatic communication system now available or under development. We are now in the first phase of a marketing agreement with Emerson Electric.

Success in today's rapidly changing energy world requires highly skilled and motivated personnel dedicated to meeting the needs of our customers. These people require the opportunity to advance in an exciting and challenging field. NEESPLAN has the potential of retaining and attracting the talented people necessary to solve the energy problems of the future.

Contingency Planning

The oil embargo, coal strikes, natural gas shortages, and the recent revolution in Iran present a clear message -- today's energy company must prepare to meet a wide array of contingencies.

NEESPLAN sets ambitious goals for conservation and load management. Achieving these goals is not completely within our power. Customers must participate in great numbers. We must gain regulatory approvals and cooperation. And, we must prepare for the possibility of major shifts in energy consumption patterns.

Future oil and gas shortages could cause customers to substitute electricity generated with secure domestic fuels.

Gasoline shortages could accelerate the widespread use of electric vehicles.

These and many other contingencies could combine to thwart our best efforts to reduce growth. Through it all, we must continue to provide reliable electric service.

NEESPLAN recognizes this potential and plans for it. A broad range of new capacity options is, and will be, under constant assessment. Timely decisions must be made if we fall short of our conservation and load management goals.

Our current assessment is that nuclear power is the best option to meet any need that may develop beyond NEESPLAN's capacity goals. For this reason, we will continue our efforts to site the planned NEP 1 and 2 nuclear units.

Another NEESPLAN contingency strategy calls for the constant assessment of alternate generating sources. We will be prepared to increase our planned commitments in this area if the economics improve sufficiently and if we need additional capacity beyond the NEESPLAN targets.

Contingency planning for areas other than meeting our capacity requirements are also addressed in NEESPLAN.

To be successful, NEESPLAN must, and will, be constantly reviewed and updated, based on changing world, national and regional conditions.

Energy Benefits for New England and the Nation

NEESPLAN has the potential to provide substantial savings to our customers and benefits to our investors. It also can help achieve important regional and national energy goals.

NEESPLAN exceeds every energy goal set for utilities by the President and the Congress. On July 15, 1979, the

President addressed the international oil crisis. He put a cap on oil imports and later called for utilities to reduce their oil consumption by half before 1990. Under NEESPLAN, we will meet this goal by 1981 and could exceed it by 1985.

By expanding our search for domestic oil, we will be importing only four million barrels of oil, less than one-fifth of what we are using today. We will be substituting American coal, increasing our energy independence, and reducing our payments abroad.

We pledge to continue to meet all environmental standards when accomplishing these tasks. We have already worked with state and federal environmental agencies to develop a detailed program to convert the units at Brayton Point to coal. Similar approaches will be used as we work to accomplish conversion of the Salem units.

In addition to reducing dependence on foreign oil, we will be devoting our resources and efforts to conservation. We will aid our customers in their drive toward energy efficiency. We will encourage the use of energy-efficient appliances, solar systems and new conservation techniques.

All of these programs are consistent with national energy policies. Each is particularly significant for the Northeast. New England is especially dependent on foreign oil and it is far removed from other, basic fuel sources. As a result, we must use New England's resources, ingenuity and thrift, to advantage. This is precisely what NEESPLAN is designed to do.

NEESPLAN
FIRST UPDATE

November 1980

NEESPLAN 1981 - 1996 is the first update of a long-range corporate plan developed by and for the companies comprising the...

NEW ENGLAND ELECTRIC SYSTEM *

New England Power
Massachusetts Electric
Narragansett Electric
Granite State Electric
New England Energy Inc.
New England Power Service

The first issue of NEESPLAN covering the period 1980 - 1995 is described in a booklet attached to the end of this report. Further information on this first issue can be received by writing NEESPLAN, 25 Research Drive, Westborough, MA 01581.

NEESPLAN is one energy system's approach to planning for the 1980's and 1990's. It is based on an intensive conservation and load management program designed to limit the growth in demand for electric energy to the minimum consistent with a strong regional economy.

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* See Section XI.

I. Executive Summary

A year ago, New England Electric System introduced NEESPLAN — an action plan designed to accomplish two key goals.

- Reduce foreign oil use from 73 percent to 10 percent of our energy needs, and...
- Keep our customers' electric energy costs to a minimum consistent with reliable electric service.

This first update of NEESPLAN reports on our progress, refines our analysis, and, most importantly, expands on our goals.

It reflects the experience gained from a year that included yet another significant run up in oil prices and a major increase in our nation's rate of inflation.

The programs in this updated NEESPLAN will improve the security of our fuel supply, increase our flexibility, and save our customers an estimated $1.35 billion over the period 1981 - 1996.

Conservation and Load Management

Our revised NEESPLAN conservation and load management objective is to hold peak demand and energy growth to an average of no greater than 1.8 percent and 2.1 percent per year respectively.

This is a refinement of the targets established a year ago (1.9 percent and 2.4 percent) and is based on a year of experience implementing our load management and conservation strategies and our forecast of a lower natural growth rate.

Attainment of our new objective will allow the deferral of any new generating capacity beyond our present commitments to a period beyond the NEESPLAN planning horizon of 15 years.

To meet this objective, we will, with the approval of our regulatory commissions, institute new rate forms designed to induce additional customer conservation and load management actions. We will expand our residential and commercial and industrial energy audit programs and attic insulation incentive program.

We will move ahead with development of our patented load control system (TWACS), and we will continue our efforts to shave our winter and summer peaks through heat storage and air conditioner cycling, respectively.

Finally, we will continue to assist customers interested in utilizing cogeneration, solar and other renewable resources.

Diverse Mix

As an electric utility, we provide an energy conversion and energy delivery service. We take basic energy resources: coal, uranium, oil, natural gas, water power and other renewable sources and convert these to electricity. We then deliver this new form of energy to our customers.

Over-reliance on any single source of basic energy is fraught with problems. Over the past decade, we have experienced natural gas shortages, OPEC embargoes, droughts and strikes by coal miners. These experiences have made us well aware of the advantages of diversifying our basic energy mix.

Diversity continues to be a fundamental objective of NEESPLAN. A year ago, 74 percent of our energy needs were being generated by foreign oil. Thanks to our ability to burn some coal at our Brayton Point Station, that total was reduced to 63 percent in the first half of 1980. By the end of 1982, we expect our reliance on foreign oil will be no more than 27 percent.

By 1996, NEESPLAN calls for an energy mix of 49 percent coal, 25 percent nuclear, 6 percent hydro, 10 percent foreign oil, 6 percent domestic oil and 4 percent alternate energy sources. Our coal capacity will have the capability to convert back to oil in a matter of only a few weeks, should coal supplies be interrupted.

This diverse mix reduces our reliance on foreign oil to a realistic minimum and provides us with great flexibility to adjust to changes in resource supply.

Coal Conversion

Converting some of our present oil-fired generating capacity to coal is a major step toward achieving our diverse mix and foreign oil reduction objectives.

A year ago, our coal conversion program targeted our Brayton Point Units 1, 2 and 3 and our Salem Harbor Units 1, 2 and 3 for conversion. NEESPLAN now calls for the program to be expanded to cover our South Street, Providence Units 12 and 1 and the Mt. Tom Station.

The Mt. Tom Station is not a System-owned plant, but the System has a 38 percent share of the output and the plant is expected to be converted to coal within the NEESPLAN time frame.

Fuel Supply — Coal

Coal requirements in 1980 were purchased from mines in West Virginia, Virginia and Pennsylvania. These purchases were transported to New England by vessel from the ports of Philadelphia, Baltimore, Newport News and Norfolk.

Starting in 1983, a significant portion of our coal needs will be delivered by a new self-unloading, coal-fired transport ship. This will be the first coal-fired transport ship commissioned in the last 25 years. It represents our further commitment to reduced reliance on foreign oil.

Fuel Supply — Oil

Another major step toward achieving our diverse mix and foreign oil reduction objectives, lies in our ability to discover and produce domestic oil and gas supplies.

To achieve our objectives we will need to be producing some 5.5 million barrels of domestic oil per year by 1996.

To meet this target, we have more than doubled our domestic oil and gas exploration and production program through our fuel subsidiary, New England Energy, Inc. (NEEI).

NEEI, through July 1, of 1980, had invested $112 million in oil and gas exploration, resulting in 12.4 million barrels equivalent of proved and probable reserves. NEEI's actual production over the next 12 months is estimated to exceed one million barrels of oil or gas equivalent. The savings associated with this production are expected to approach $4 million. Over $3 million in fuel cost savings have already been passed through to our customers.

In the past, NEEI worked as a one quarter partner with Samedan Oil Corporation, an experienced oil and gas exploration company. In 1980, this was doubled and NEEI is now an equal partner in all of Samedan's domestic operations. This was the first of two major steps taken by NEEI in the past year. The second is a new equal partnership with the Dorchester Exploration Company. This new partnership is currently awaiting regulatory approval.

Alternate Energy Sources

As part of our update of NEESPLAN, we are doubling our commitment to alternate energy. We are increasing our target to obtain energy from 100 to 200 megawatts of generation. We expect to obtain some one million megawatthours of energy per year by 1996 from these sources.

In the first edition of NEESPLAN, we planned an additional 100 MW from conventional sources. Our latest analysis indicates that it will be unnecessary to build any capacity beyond our current commitments during the 15-year planning period.

Our program to purchase electric energy from alternate sources is well under way. We have committed to buy the energy from a 15 MW low-head hydro project and from a solid waste plant, both located in Lawrence, Massachusetts.

In addition, we have been commissioned to engineer, construct, and monitor what could be the world's first wind farm. This project will be built for U.S. Windpower, Inc., on a site in southern New Hampshire and the power will be purchased by a local utility.

During 1980, our plans to build and operate a wood-burning generating station were further developed, and we anticipate site and equipment selection in 1981.

Negotiations to purchase the energy output from additional small hydro projects, solid waste facilities and wind-power generators are under way.

Contingency Planning

Our understanding of the uncertainties associated with all aspects of energy has increased over the past year.

We may not be able to achieve our very ambitious conservation and load management objectives due to consumption patterns that shift away from fossil fuels to electricity.

(The electric car is an example.) Fuel supplies could be disrupted by international events, strikes of organized labor, by natural gas shortages, and the list goes on.

Today's already long lead times for new capacity additions may lengthen. The rate of inflation may increase again, causing even greater difficulty for our capital intensive industry.

For all these reasons, we have instituted a monitoring program to provide early detection of shifts in consumption patterns. This program has been designed and placed in operation. In addition, we will continue to assess a broad range of capacity options that would permit us to build facilities to meet unexpected demand. And we have developed the flexibility to shift fuel supplies if disruptions occur.

New England Electric, through its representation in the New England Power Pool, is also evaluating the potential of further imports of Canadian hydro power. To the extent that additional energy can be obtained from this source to reduce oil consumption in New England at a cost which will be beneficial to our customers, we would expect to participate to the fullest extent possible.

New Business

During the past year, we have undertaken a major review of new business opportunities. These ventures will build on our successes with NEEI and TWACS. During the year we commissioned the construction of a coal-fired transport ship to bring coal to our generating stations, and initiated The Energy Institute to offer educational programs in energy conservation and technology.

Other opportunities will be continually reviewed to provide solutions to energy problems, challenges to our employees, new services to our customers and an ever better return to our investors.

Financial Considerations

As revised, NEESPLAN is expected to reduce capital requirements over the planning period by over $2.6 billion, from $9.9 billion down to $7.3 billion.

With NEESPLAN, we estimate capital expenditures for conventional generation, transmission and distribution will be reduced by $3.9 billion over the period 1981-1996.

Partially offsetting these reduced capital expenditures will be increases for NEESPLAN projects, including $238 million for coal conversion, $274 million for load management, conservation, and alternate energy sources, and $744 million for expanded domestic fuel exploration and development. The coal conversion construction expenditures for the period 1981-1996 do not include $80 million budgeted for 1980.

A substantial portion of the required capital will be produced internally. However, some outside, permanent financing will be necessary, especially over the next five years.

Our plans suggest we will need no additional public sales of common shares from the mid-1980's through the remainder of the NEESPLAN planning period.

NEESPLAN has the potential to significantly improve our investors' earnings over the next 15 years. Regulatory agencies here in New England and in Washington are fully aware of the need for energy conservation, load management, secure energy resources and coal conversion.

We have incorporated our total NEESPLAN approach in the rate applications requested and ruled on in 1980. In these requests we asked for an "incentive return" for our conservation companies, and "forward looking" approaches to setting rates for our companies.

The Massachusetts and Rhode Island commission orders received late in 1980 did include "forward looking" adjustments, allowances for attrition and precedent setting returns for our companies. We are encouraged by the orders received in 1980, and believe they are a real measure of commission support for our planning efforts.

Energy Benefits for New England and the Nation

Like the original, this edition of NEESPLAN is designed to meet the needs of our customers, our investors, New England and the nation. This plan will save some $1.35 billion for our customers. It will offer them help in making wise and efficient energy choices. It holds promise of a fair return to our investors during a period of inflation, and the opportunity to diversify our interests and provide new investment opportunities.

NEESPLAN furthers national and regional goals. It will reduce dependence on foreign oil, increase energy independence and limit foreign payments. It will lead to innovation in conservation, load management and alternate energy technologies. It will more than meet all of the energy goals set by Congress and the U.S. Department of Energy.

The energy crisis is not an insurmountable problem. Rather, it is a challenge which leads to new opportunities. We in the U.S. have sufficient basic energy resources. The question is: do we have the time to develop these resources and do we have the will.

When issued last year, NEESPLAN was the blueprint for our new approach to energy problems. This year, we have refined our analysis, expanded our goals, and begun implementation. Our commitment has not changed.

November 1980

XI. New England Electric System

New England Electric System is a public utility holding company registered under the Public Utility Holding Company Act of 1935. New England Electric System itself does no public utility business, but owns 100% of the common stock of four electric utility operating subsidiaries: Granite State Electric Company (Granite), Massachusetts Electric Company (Mass. Electric), The Narragansett Electric Company (Narragansett), and New England Power Company (NEP). In addition, New England Electric System has two other wholly owned subsidiaries: New England Power Service Company (NEPSCo), a subsidiary service company, and New England Energy Incorporated (NEEI), a fuel subsidiary. The subsidiaries of New England Electric System are collectively referred to herein as "New England Electric," "the System," "NEES," or the "NEES System." NEES System headquarters are located at 25 Research Drive, Westborough, Massachusetts 01581, telephone number 617/366-9011.

The name "New England Electric System" means the trustee or trustees for the time being (as trustee or trustees but not personally) under an agreement and declaration of trust dated January 2, 1926, as amended, which is hereby referred to, and a copy of which as amended has been filed with the Secretary of the Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of New England Electric System binds only its trust estate, and no shareholder, director, trustee, officer or agent thereof assumes or shall be held to any liability therefor.

Mr. **Fuqua**. Thank you very much, Mr. Nichols.

We have a rollcall vote, and we are going to have to take a short recess.

Mr. Harkin has already led the advance party and will be back to resume the hearing, probably before I get back. We will stand in recess for a few minutes and then resume.

I apologize for the inconvenience.

[Recess.]

Mr. **Harkin** [presiding]. The subcommittee will come back to order.

Mr. Mitchell, if you are prepared, why don't we go ahead and move to you, understanding what the chairman has already said, that without objection all the statements will be made part of the record.

Please proceed as you so desire.

STATEMENT OF RALPH MITCHELL, VICE PRESIDENT, CONSERVATION AND RENEWABLES, ARKANSAS POWER & LIGHT, LITTLE ROCK, ARK.

Mr. **Mitchell**. Thank you very much, Mr. Chairman. I think most of the speeches today have adequately established the serious and chronic financial condition of the electric utilities industry and further discussion of that might be redundant.

But I do think one speaker yesterday, Mr. Charles Curtis, did a good job of summarizing the various proposals for relief into four categories, which he designated as the risk compensation option, the risk reduction option, the diversification option, and the deregulation option.

And I think the first two—the risk compensation and reduction options—have been adequately dealt with by Mr. Ferrar, Mr Benore, Mr. Swidler, and others.

And as for the fourth option—deregulation—I am in agreement with most of the speakers that not enough work has been done to determine whether that is, in fact, a viable option at all, and I would not label it currently as a solution option.

Therefore, I'd like to spend my little time summarizing my testimony on the third option—diversification. I have heard essentially two schools of thought on this issue. One school says that a utility must become financially healthy before, and in order to diversify. And the second school says that a utility must diversify in order to become financially healthy.

In my opinion, neither statement is an absolute. Certainly, utilities must be allowed to earn a fair rate of return on their franchises, and business diversification is not a panacea that will relieve that burden from the regulators. But I do consider diversification potential as both a separate and new business opportunity, each of which must stand on its own two feet. And in many instances, as a potential threat to the economic viability of the traditional regulated business.

I would like to discuss one specific case in point—cogeneration. I think the staff advised me, Mr. Chairman, that you would be interested in the motivations of a utility in the diversification area, and I'd like to briefly describe the evolution of Arkansas Power & Light interest in cogeneration today. Essentially with the 1978 Energy Act clearly promoting incentives for cogeneration in the nonutility sector, we started a study of what the consequences might be on our system. We conducted a study beginning in 1978 of some 1,500 steam producing industrial boilers in our territory with an eye toward identifying those that might be economically viable for cogeneration facilities.

We found 35 such facilities, primarily in the wood products, the aluminum, chemical, and oil industries that used about 7 million pounds per hour of steam in our service territory. We began to discuss in some detail with all 35 customers what their pursuits would be in terms of cogeneration or energy supply for the future, and we found that it was unlikely that any of those 35 firms—and they are large firms, such as Potlatch, Weyerhaeuser, Alcoa, Reynolds, International Paper, Dow—would make a major capital investment in cogeneration for one or more of three reasons.

The first was essentially capital limitation. They have a finite capital supply, as does virtually anybody, and given a choice, they would prefer to put their limited capital into productive facilities rather than an energy supply, if you will. Furthermore, the few that had done some economic analysis of cogeneration found that the projects would not produce the rate of return sufficient to meet the hurdle rate of return criteria in their corporation, and so it is unlikely that they would make that investment.

Second, we found that many thought they did not have the inhouse expertise, either managerial, operating, engineering, or otherwise to build and operate generation, particularly if they were talking solid fuel generation, which the Fuel Use Act seemed to point them toward.

Third, we found that they had environmental concerns, Mr. Chairman. Again, looking at the Fuel Use Act, they were looking at solid fuel, and they wanted to reserve their finite increments of air and water quality for productive capacity rather than for generation on coal, for instance.

So that led Arkansas Power & Light to our own concept. We developed the idea that if we could build and operate cogeneration facilities to serve industrial steam supply and our own electric grid, that it would provide most of the advantages of cogeneration to the industry and certainly to our service territory and relieve industry of the three disadvantages that they perceived.

The first problem we ran into is that we wanted to optimize or maximize electric production from serving the steam supply and that led us to the combined cycle cogeneration plant, to serve that 7 million pounds per hour of steam requirements that I referred to.

If industry developed single-cycle cogeneration plants, it would produce about another 100 to 125 megawatts capacity. However, with combined cycle systems, we could see the potential of 1,500 megawatts on our system serving that same steam supply. The first difficulty we ran into with combined cycle is it requires clean fuel—No. 2 oil or natural gas. And these, of course, are the fuels we were trying to get off. This led us to coal gasification. We currently have three feasibility studies underway envisioning using petroleum coke in one instance, lignite in another, and Illinois coal in another, as a gasification feed stock to produce a clean medium Btu gas which we would pipeline to the industrial locations and locate combined cycle cogeneration plants at those locations.

The major difficulty with this is that utilities are not placed in an equal competitive ownership position with regard to cogeneration, as compared to any other entity in society. Basically, there are three benefits provided or three incentives provided to cogeneration—nonutility-owned cogeneration—those being freedom from price regulation under PURPA, the avoided cost for electric sales to the utility system under PURPA, and the extra 10 percent energy tax credit under the Energy Tax Act of 1978.

We have a legislative effort underway to remove the ownership limitation on utilities and thus provide the same incentives to utility-owned systems.

Now quite candidly, the reason we are interested in this is, first of all, to protect our existing industrial electric market. Over time, if cogeneration develops with alternative ownership, we see a shrinking revenue base in our industrial market.

That's our primary objective; but secondly, we look at a great opportunity to diversify into a brand new business for us—that is, steam sales—and finally, the higher rate of return on that venture, should it be deregulated, which would come with the higher risk in such venture.

Now I think there are many valid and compelling reasons for providing this equal competitive ownership opportunity for utilities which I have covered in my testimony and I won't summarize here.

Let me say, finally, that I believe that more cogeneration potential will be realized from full utility participation in the market. I believe electric utilities would maximize electrical output available from the service of the finite steam requirements, more so than other ownership options.

I believe utility participation will lead to faster development of advanced technologies in cogeneration, and I believe utilities will do a better job of integrating the dispersed generating technology with our tradition central station system for system reliability.

And finally, I believe that aggressive utility participation in the cogeneration market will prevent a potentially adverse impact on its ratepayers that could occur if it loses a large portion of its industrial revenues from industrial or third-party generation development.

This last point in particular applies equally to the many business opportunities expected to develop from the various new conservation services and alternative energy supply markets being provided. Utilities must be allowed to compete in these businesses on an equal competitive basis, and we would urge your support for legislation that would accomplish that.

Thank you very much, Mr. Chairman.

[The prepared statement of Mr. Mitchell follows:]

STATEMENT BY ARKANSAS POWER & LIGHT COMPANY

PRESENTED BY

RALPH C. MITCHELL, III
VICE PRESIDENT
CONSERVATION & RENEWABLE RESOURCES

BEFORE THE HOUSE SUBCOMMITTEE

ON

ENERGY DEVELOPMENT AND APPLICATIONS

JUNE 24, 1981

STATEMENT BY ARKANSAS POWER & LIGHT COMPANY

I. INTRODUCTION

Mr. Chairman and members of the Committee, I appreciate this opportunity to appear before you to discuss some of the current institutional issues, the the resolution of which will impact the future availability, reliability, and economics of electric energy in this country. I am Ralph C. Mitchell, III, Vice President, Conservation & Renewable Resources, for Arkansas Power & Light Company (AP&L), Little Rock, Arkansas.

In view of the appearances in this hearing of Dr. Terry Ferrar, Vice President of the Edison Electric Institute, and Mr. Guy Nichols, Chief Executive Officer of New England Electric System, both of whom have presented the views of the investor-owned electric utility industry on a broad range of institutional and regulatory reform needs, I will limit my remarks to one area of specific concern -- cogeneration and small power production. However, I would point out that many of the principles and issues currently being considered with regard to the promotion and development of cogeneration and small power production are equally applicable to other energy conservation, load management, and renewable resource technologies which can contribute to our energy future. I would also observe that these additional sources of energy are often based upon new technologies and should, therefore, be of specific interest to this Committee. For instance, advanced coal combustion, advanced combined cycle generation, coal gasification, fuel cells, and solar technologies will all have application in the cogeneration market.

Furthermore, the ultimate legislative and regulatory treatment of cogeneration by the Congress and the various regulatory authorities will have a substantial impact on the future of the nation's electric utilities in at least two ways:

(1) If the present legislative and regulatory bias toward nonelectric utility development of cogeneration is continued, the industry faces a potential loss of electric revenues which can only exacerbate our current financial difficulties.

(2) The bias effectively limits, if not precludes, electric utility diversification opportunity to enter a logical new business -- the sale of steam.

And, finally, the issue of deregulation of segments of the electric utility business has been raised in recent times and in various forums. Certainly this area, cogeneration, is one in which adequate competition, encouraged by the Public Utility Regulatory Policies Act of 1978 (PURPA), does exist. In my view, this obviates any need for regulation of an electric utility cogeneration venture.

Since I have been asked by the staff of the Committee to discuss the motivations leading to our position on the issues facing public energy policy makers, I believe it might be most helpful for me to briefly recap the AP&L experiences which have led to our cogeneration initiatives.

II. THE AP&L COGENERATION STORY

In 1978, we commissioned a study designed to identify all steam-producing industrial boilers in our service territory by size, age, fuel source, and other characteristics. At the time, we had two basic interests:

(1) Since most of these boilers were fueled with oil or natural gas, we were concerned with estimating the number which might convert

to electricity, either as a result of economics or the passage of the Powerplant and Industrial Fuel Use Act, since that could have a substantial impact on our load and capacity planning.

(2) We also wanted to identify those applications with high potential for cogeneration.

From that survey of almost 1,500 industrial boilers, we determined that 33 high volume and high load factor steam users were strong potentials for cogeneration. This group represented almost seven million pounds per hour of steam requirements. They were all industrial plants, generally in the wood products, paper, aluminum, chemical, or oil industries.

We interviewed these companies rather extensively to determine their likely courses of action with regard to their future supply of energy. We found that these industries are fully aware of the desirability of cogeneration from a fuel use efficiency standpoint and are familiar with the incentives provided by the Congress to encourage its development. However, major cogeneration investment commitments by the industries are unlikely for at least one of three reasons.

First, an industrial company -- like any other entity -- has finite capital resources available. Such an industry prefers to use its limited available capital for investments which will expand its production capacity or reduce the unit cost for its primary business product. The long-term survival of any business depends upon its having adequate and competitive productive capacity available to serve its market; quite frankly, at present many of American industries have difficulty accumulating sufficient capital to satisfy this primary objective. In the cases in which an industrial firm does have adequate capital resources, investments in cogeneration must compete with all other investment opportunities on the basis of overall profitability to the company. Many have found that the payback period for cogeneration exceeds the firm's criteria for the commitment of new capital investments, especially for industries in which energy costs are a small proportion of total production cost.

Second, many industrial firms are reluctant to pursue cogeneration due to a lack of managerial, technical, operating, and/or environmental skills available in its organization for the development of a cogeneration project. This is especially true if the company is considering a solid fuel, such as coal, or a synthetic fuel. And, it is also a particularly important factor for medium and smaller size firms.

A third, and very significant, deterrent to industrial cogeneration is the finite increments of air and water quality available, as well as land resources. Again, an industrial company would prefer to use these limited resources to pursue its primary line of business, and not in power generation -- most especially solid fuel burning power generation.

We also discovered that in the unlikely event that the industrial firms should opt to cogenerate, it would probably be with single cycle cogeneration equipment. If all 33 firms made this selection, it would lead to only slightly over 100 megawatts of additional electric capacity in our region.

This information led us to the conclusion that a highly desirable strategy would be for AP&L, the electric utility, to build, own, and operate cogeneration facilities designed to serve the steam requirements of industry. We saw the opportunity to provide industry with all of the advantages of a cogenerated energy supply and, at the same time, remove the three constraints to their own development -- capital limitations, operating expertise, and environmental considerations.

We also saw the opportunity to enhance the electrical output through the use of combined cycle cogeneration equipment, with which we could potentially provide approximately 1,500 megawatts of additional electric capacity for our grid.

Two difficulties remained, and the first was fuel. The combined cycle plants would require a clean fuel, either oil or natural gas, and these were the precise fuels on which we were attempting to reduce our dependence. This led us to the concept of building a central coal gasification facility which would produce a clean medium BTU gas, a gas pipeline distribution system and combined cycle cogeneration facilities at the industrial locations. We envisioned all or partial utility ownership of the system which would sell steam to industry and electricity to the utility grid.

However, the second difficulty we encountered was the legislative and regulatory treatment of cogeneration which patently favors nonelectric utility development. Electric utilities are simply not provided an equal, competitive ownership opportunity in this market.

Before I describe both the barriers and remedies we propose, let me report that AP&L is continuing its efforts to make our gasification/cogeneration concept a reality. We have several economic, technical, and environmental feasibility studies currently under way. We have active, ongoing negotiations with the industrial customers, some of which look very promising. And, we are supporting HR 2876 and HR 2946, which would have the effect of providing electric utilities the equal, competitive ownership opportunity we must have.

Succinctly and candidly, our interest or motivation to compete in the cogeneration market stems from three objectives.

(1) Above all, we want the opportunity to protect, or continue to serve, our existing industrial electric energy market. We do not want to see a potential decline in our industrial revenues over time.

(2) We see an exciting diversification opportunity in steam sales, particularly, but also the sale of by-products from the gasification process.

(3) We are very excited by the prospect of creating an unregulated, cogeneration subsidiary business with its potentially higher rate of return commensurate with the higher risk perceived.

III. THE CASE FOR ELECTRIC UTILITY PARTICIPATION

Cogeneration does have a potentially important and beneficial role in our nation's energy future, but industrial investment in cogeneration is not the sole nor optimal way to fulfill cogeneration's potential role in our nation's future energy mix.

Based on our surveys and discussions with industrial customers, the potential for industry-financed cogeneration to meet the goals of national policy is severely limited.

The limited potential for industrial investment in cogeneration suggests the alternative benefits of providing equal, competitive ownership opportunities for utilities. First, utility expertise and experience in the capital markets is advantageous for the future deployment of cogeneration technologies. Cogeneration has many attractions for both electric utilities and users of process steam and hot water. Consequently, electric utilities throughout the nation are actively pursuing possible arrangements with industrial firms. However, even a rapid expansion of industrial cogeneration financed by the industrial firms would not have a significant impact on utility financial problems. The current financial problems of utilities will gradually improve, allowing them to finance new generating capacity which is the most cost-effective. Even in the immediate future, utilities need to invest in new capacity such as coal and nuclear to meet load growth in regions with inadequate reserve margins or in regions where reduction in the use of oil and gas for electricity generation is imperative. Allowing utilities equal, competitive investment opportunity with respect to cogeneration which reduces scarce fuel use will help to ensure that future capital investments (both central station and dispersed energy facilities) are made in the most cost-effective manner. Utilities can then access capital markets to deploy cogeneration where it is in the interest of the ratepayer and the shareholder. Utilities also have the expertise and experience to arrange project financing for cogeneration facilities, using capital from a wide variety of sources.

Second, since cogeneration is an ancillary investment of industrial concerns, investors frequently require cogeneration projects to be more profitable than their essential projects. A survey by Pacific Gas & Electric Company found that the minimum acceptable return on investment for industrial cogeneration projects is usually over 25%. Because electricity production is the main business for electric utilities and because electric utilities are accustomed to longer pay back periods, investors may accept a lower rate of return. Thus, allowing equal, competitive ownership would increase the attractiveness of cogeneration to the investment community.

Third, incentives for utility ownership of cogeneration may benefit small industrial or commercial concerns. While such a small user might not find it economical or feasible to invest in cogeneration alone, a third party might find it advantageous to cogenerate for a cluster of smaller users. Utilities, relying on their knowledge of small users and technical expertise, would be the ideal facilitator for such cogeneration projects.

Finally, electric utilities can provide the systems and resources capable of more effective integration of cogeneration and other dispersed energy technologies into their centralized systems. In designing a cogeneration system to serve a particular industrial steam requirement, an electric utility would no doubt optimize electrical output and its reliability to the utility's grid. An industrial firm does not have the same incentive to maximize the benefits of a cogeneration facility to the electric utility system, and thus the public.

Utilities have two additional characteristics important to the development of cogeneration: First, experience with the operation of coal and other type boilers, environmental protection equipment, fuel procurement and handling, and waste disposal; and second, unique knowledge of the energy consumption patterns of their customers and a frequent contact with them. This experience and knowledge should be utilized. Consumer confidence in the technical abilities of utilities, as well as their permanence, makes them an ideal institution to promote the development of cogeneration.

Thus, where cogeneration is a cost-effective means of promoting energy conservation that would meet our national energy goal of reduced reliance on imported oil, the public interest would best be served by removing legislative barriers and disincentives to utility participation in the cogeneration market. The specific issues requiring revision are the inequality of treatment under PURPA with respect to utility ownership of cogeneration facilities and equal treatment with respect to energy tax credits for electric utility-owned cogeneration projects. If these two barriers to competitive utility ownership of cogeneration are removed, an electric utility could provide all of the benefits of cogeneration to an industrial steam user and remove three disadvantages perceived by industry: capital constraints, skills availability, as well as environmental/land limitations. The industrial community broadly supports this concept.

The specific legislative actions required are covered in the following two sections.

IV. EQUAL TREATMENT FOR ELECTRIC UTILITY-OWNED COGENERATION

The regulations issued by the Federal Energy Regulatory Commission (FERC) pursuant to Section 201 of PURPA grant "qualifying facility" (QF) status to cogeneration and small power production facilities which are less than 50% utility-owned. QF status entitles cogenerators to a number of rate and regulation exemption privileges. FERC regulations implementing Section 210(e) of PURPA exempt QFs from state regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I and Part II, Sections 210-212), and from the Public Utility Holding Company Act. In addition, QFs are entitled to sell excess power to utilities at avoided cost rates and purchase back-up power from utilities at nondiscriminatory rates.

Cogeneration facilities which are more than 50% utility-owned do not qualify for these benefits. As such, utilities continue to have their wholesale rates regulated by FERC and their retail rates subject to state rate regulation. In addition, utility-owned cogenerators are subject to the prohibitions and requirements of the Public Utility Holding Company Act. As pointed out in the following paragraphs, these restrictions provide a strong disincentive to utility cogeneration development.

There are two main reasons an electric utility cogeneration entity must have the same incentives that PURPA provides for an industrial-owned facility. First, the industrial firm is clearly interested in steam at a competitive cost. Since there are two revenue streams to the cogenerator -- electricity and steam sales -- the price paid for the electrical output is a major determinant of the cost for the steam output. Therefore, if an industrial-owned facility sells its electrical output to the utility system at avoided cost, but a utility-owned cogeneration facility receives less than avoided cost for electrical output, the electric utility would necessarily have to price the steam at a higher and consequently less competitive rate. Second, if the rate of return is regulated for a utility-owned facility and unregulated for an industrial-owned facility, then it is likely that given a choice between these two entities, an investor would seek the investment that provides the higher return on capital. This is particularly true given that the industrial cogenerator has a guaranteed market for its electrical product under PURPA reducing risk for the industrial investor. Thus, utilities are at a competitive disadvantage in attracting investment capital for cogeneration projects.

The Energy Tax Credit (ETC), which is available with respect to cogeneration property, is not allowed for "public utility property." However, a utility cogeneration facility which is "qualified" under the PURPA regulations might not be considered "public utility property" as defined in Treasury Reg. S1.46-3(g)(2) in that such property is not regulated in the traditional cost of service manner. Therefore, a public utility may only be able to take advantage of the ETC if it owns 50% or less of a cogeneration facility. Any restriction on utility ownership percentages acts as a disincentive for utilities interested in cogeneration and should be removed. Further, the tax benefits applicable to owners of "qualified cogeneration facilities" should be made available to utilities on an equal basis.

V. EQUAL TREATMENT WITH RESPECT TO TAX CONSIDERATIONS

Although this Committee exercises no jurisdiction over tax code changes, any discussion of electric utility ownership of cogeneration facilities requires brief mention of the Energy Tax Act of 1978 (P.L. 95-618) and the Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223). The Energy Tax Act of 1978 provided a general exclusion from the Energy Tax Credit for property which is owned or leased by a public utility. In the Crude Oil Windfall Profit Tax Act (IRC Section [48(l)(17)]), property which would otherwise qualify for an additional ETC will not qualify if it is public utility property. Such property includes solar, wind, biomass, recycling, and cogenerating equipment. Many kinds of property to which the public utility exclusion applies are directly related to the function of generating electricity; this exclusion is specifically applicable to cogeneration equipment as defined by the Crude Oil Windfall Profit Tax of 1980 (IRC Section [48(l)(14)]). Cogeneration facilities provide for energy conservation by utilizing an additional form of energy which would otherwise be wasted. Ownership of cogeneration facilities by utilities, as well as nonutilities, should be encouraged. Accordingly, if tax incentives are available for nonutility owners of cogeneration facilities, they should also be extended to utilities. In that the conservation offered by cogeneration can be quite substantial when applied to industrial uses, applying tax credits equally to utility- and nonutility-owned cogeneration facilities would be appropriate if it would contribute to reducing our dependence on scarce fossil fuels.

VI. CONCLUSION

The legislation and regulation which preclude or discourage an electric utility from directing its expertise to and investing its capital in cogeneration facilities are not consistent with our national energy goals and tend only to delay the development of an economy which is not overly dependent on scarce fuels for most of its energy needs. To preclude or discourage a utility from investing in cogeneration facilities can lead to the following consequences:

(1) Less realization of the total cogeneration market than would otherwise be the case.

(2) Less electric capacity from cogenerating facilities than would likely be provided with utility investment.

(3) Slower development of advanced technologies such as advanced coal combustion systems, advanced combined cycle generation, coal gasification, fuel cells, and solar applications.

(4) A potentially adverse impact on the financial health of the electric utility industry or its ratepayers through the loss of a segment of its industrial market, and the revenues from that market.

(5) A potentially less reliable electric system if substantial reliance is placed upon cogeneration capacity outside the direct control of the electric utility.

Finally, I fail to see the rationale behind the retention of regulation upon an electric utility in a highly competitive market. If regulation is in fact a substitute for competition in a franchised monopoly market; and certainly with PURPA, Congress has provided ample assurance that competition in cogeneration will exist; then the need for utility regulation in that market no longer exists.

With cogeneration, the Congress has a unique and specific opportunity to address the question of deregulation of a segment of the electric utility business, one in which there is ample competition and in which electric utilities should have the expertise and resources to compete effectively. Further such opportunities will no doubt occur, particularly as additional decentralized energy supply technologies become economically attractive for deployment. However, this one -- cogeneration -- is at that stage now. I urge your support of HR 2876 and HR 2946 which would provide that equal competitive business opportunity to electric utilities in the cogeneration market.

Mr. FUQUA. Thank you very much, Mr. Mitchell. We appreciate your testimony.

Our next witness will be Mr. Irwin Stelzer, president of the National Economic Research Associates.

STATEMENT OF IRWIN M. STELZER, PRESIDENT, NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC., NEW YORK, N.Y.

Mr. STELZER. Now Mr. Chairman, let me do two things unusual for an economist. I will try to stick to the subject, and I will try to be very brief.

Mr. FUQUA. And talk with one hand?

Mr. STELZER. Yes. But be careful of those who think they know everything and don't tell you about the other hand.

Your letter suggested that the committee was interested in changes in the industry that might facilitate market acceptance of the new technologies. I start with no prejudice for or against hard path, soft path or any of the other paths that people seem to prefer. My only bias is in favor of letting the customer decide what he wants, and then have free access to it. And the question is, How do we get those technologies made available to him?

There are four institutional arrangements in the industry, that impede the attainment of the objective that the committee has. There may be others, but I think these are the four most important.

First, the industry and its regulators have an infatuation with uneconomic pricing and a desire for subsidies. Many electric and gas utilities price their product as though it were being produced years ago. A notable exception is New York. As you know, newer generating capacity and new gas supplies are much more expensive than old. Yet energy is sold to customers based on average historic cost. This leads them to using more energy than is economic.

But, and more important for your purposes, the effect on new technology is profound. The new technologies compete for customer acceptance at current cost. They're competing with components—steel and glass and other things—bought at current prices. And they must compete with electric and gas that is priced uneconomically at old historic costs. This tends to discourage new technologies.

Now that doesn't mean I believe that solar, wind and other technologies are truly cheaper than central power station generation. Probably the opposite is the case, particularly if you remove all tax incentives and subsidies. I do think we should let the field sort itself out, let the customers decide which technologies they prefer.

What can you do? I think you can do two things. No. 1, I think you should stay out of the tax incentive business. Tax incentives are a wonderful way to take money from poor people and give it to rich people. The tax incentives, for instance, that Congress doled out for energy conservation have gone essentially to the very wealthy at the expense of the very poor. So when you get into the subsidy business and find some technology that's very attractive to you, and you decide that you'd like to subsidize it, just decide if you want to play reverse Robin Hood or not. If you don't want to play reverse Robin Hood, pass up the opportunity to subsidize. And I mean that for nuclear, and I mean it for solar, and I mean it for anything you might want to subsidize.

Second, you should see that correct price signals go out to consumers. There's a move afoot to gut or diminish PURPA; that would be a very dangerous thing. While I think building performance standards are silly—for someone at DOE, if there's anybody left at DOE, to tell people what's best for them in building a house makes no sense—we should continue to put pressure on the States to get proper price signals out to the customers. My experience has been that PURPA has been a very useful tool in moving State commissions. I apologize if you are a State's rights person, but it has been a useful Federal code. I think you should do what you can to keep it.

The second institutional impediment to new technologies is what I will call the avoidance of the avoided cost standard. FERC has come out with rules for cogeneration rates which essentially say that the utilities must buy the power at the utility's avoided cost. That's a very sensible rule. It should be enforced. The problem is that on both sides of the bargain you have people who are not enchanted with that. The electric utilities are very nervous about the reliability of some of these alternate sources of power. The cogenerators or the small power producers—I have met with several of them—would really in their hearts like more than avoided costs. What can this subcommittee do about it? To the extent that you interact with FERC, make sure that FERC enforces its own rules. You can urge State regulators to establish avoidable costs, instead of continuing to think about them for a couple of more years.

I often say that what state regulators do best is nothing; but in this case, I think it would be better to try to get them to do something.

Also, I think you can remove the restrictions that keep our utilities out of the cogeneration business. I don't think you should force them in, but I don't think there should be any artificial barriers to their entering.

The third institutional barrier is the artificial barrier that keeps utilities out of the conservation business. I don't see any reason in reality why the hypothetical antitrust fears that we all share exist. Utilities, if allowed to enter this business, have no excess profits from the electric businesses to use as subsidies. So I would be in favor of letting them compete, but not requiring them to do so. And they should compete on an economic basis, not like in California, where they require interest-free loans from utilities. If you are going to bleed utilities for capital, that's wrong. I don't think you should do that. But I think you should let them into business.

Finally, you undoubtedly know there are two organizations in the electric business and the gas business that are supposed to be in charge of the R. & D. area: EPRI in the electric business, and GRI in the gas business. EPRI has a budget of $270 million a year now, and GRI has a budget of $80 million a year. These monies are paid for by customers. They are added onto utility bills. So we are not talking here about stockholders risking their capital. We are talking about utilities using customers' money.

It seems to me that we at least ought to pause and examine whether the traditional utility reluctance to go on the customer's side of the meter is affecting the distribution of the research and development efforts of their organizations. For instance, GRI has increased the funds devoted to demand side but still has an infatuation with capital-intensive projects that can produce gas at probably three or four times its economic price. That's a wonderful thing when you have all the old gas to roll it in with, but it isn't so attractive when you have to sell that gas to customers at $9.

So that there probably is a legitimate area of inquiry here in the whole structure of research and development efforts of the electric and gas utilities.

In brief, then, I think you could do four things. You should support economic pricing of energy by continuing the PURPA program and eliminating subsidies. You can encourage cogeneration and small power production by staying with the avoidable cost rule, with a flow-through of purchased power costs. If the electric utilities buy this power, they should be sure they can sell it at that price. Barriers to utility involvement in cogeneration and conservation can easily be removed. I think there is a very strong sense now that those were a mistake.

Finally, I think some reexamination of the structure of research and development in the industry might prove fruitful in attaining the objectives you set forth in your letter.

[The prepared statement of Mr. Stelzer follows:]

n/e/r/a
NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
NEW YORK / WASHINGTON / PHILADELPHIA / LOS ANGELES / PALM BEACH / ITHACA

TESTIMONY OF IRWIN M. STELZER, PRESIDENT
NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.

Before the

Committee on Science and Technology
Subcommittee on Energy Development and Applications
U.S. House of Representatives

Hearings on

The Future of the Nation's Energy Utilities

June 24, 1981

TESTIMONY OF IRWIN M. STELZER

Your kind invitation to share my thoughts with this Committee expressed a "strong interest in any changes in the [electric utility] industry that might facilitate or impede market acceptance" of new technologies such as fuel cells, heat pumps, wind, solar and other devices for providing energy.

In addressing that question I start with the assumption that when you refer to "market acceptance" you mean what an economist means by that term: informed consumers freely choosing among various energy sources, offered to them at economic prices. I start, in other words, with no ideological desire to walk either the "hard" or the "soft" path; no set of hidden social priorities that leads me to prefer the sun and the wind to the atom and coal; and no bias in favor of large-scale plants and their (to some engineers) soul-satisfying technology and huge scale, as opposed to conservation.

What we are really seeking is a set of programs that will enable the consumer to satisfy his self-determined needs (DOE does not, it is apparently now conceded by those occupying its shell, know best!) at the lowest possible cost.

What institutional arrangements impede the attainment of that objective? Let me discuss four: (1) uneconomic pricing and subsidies; (2) avoidance of the avoided cost standard; (3) barriers to utility involvement in conservation; (4) organizational flaws in research and development.

1. Uneconomic pricing and subsidies. Many electric and gas utilities fail to tell consumers the real cost of using a KWH or MCF, a deception abetted by several state regulatory agencies and by the current effort of some members

of Congress to remove federal pressures for reform of utility pricing. In most jurisdictions--New York State is a notable exception, Colorado a leading example--utilities persist in pricing energy as if it could be currently produced at cost levels of ten years ago.

The average historic cost of a unit of generating capacity is $250 per KW; its current cost over $1,000 per KW. The average price of gas is now $1.50 per MCF in the field, but new, unregulated supplies are going for $7.00 and would cost $10.00 from projects now being planned. Yet the energy is sold to customers--who might respond to realistic price signals by reducing usage--at average historic cost, misleading them into thinking that energy is cheaper than it really is. A new gas space heating customer, for example, isn't given a signal that says, "We may have gas for you now at $3.50 per MCF, but that price masks the fact that we're replacing it at $7.00, something you won't find out until we've got you connected to our system." So, too, with electricity.

The effect of this on the area of interest to you--new technologies--can be profound. Those technologies are competing for customer acceptance with central station generation and gas priced at rolled-in rates.[1] But they can be produced, of course, only at costs reflecting current costs of steel, manpower, glass and other resources. Hence, the newer technologies are priced at current costs while energy from conventional sources is mispriced at average, historic costs. This prevents consumers from choosing between them in an informed, rational way: the older methods seem cheaper, relative to the new, than they really are.

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[1] Rolled-in rates are the average of the costs of old, cheap gas and the current cost of new supplies. Of course, the old supplies weigh most heavily in this average.

This is not to say that I believe solar, wind and other technologies are truly cheaper than central station power. Our own studies suggest that in most cases quite the opposite is the case. For example, it is fairly clear from our surveys of actual operating experience in various parts of the country that in the absence of substantial tax incentives, solar hot water heating is not economical in most places.[2]

Whether or not solar costs will decline over time no one knows. But we do know that the tax incentives now provided have no real justification and are distributed primarily to the rich. Our study of the distribution of tax credits for conservation shows this rob-the-poor-to-pay-the-rich pattern quite clearly. In 1978, 109,000 taxpayers with adjusted gross incomes of less than $6,000 received $5,172,000 in tax credits for energy conservation expenditures averaging $47 per recipient. But the 293,000 eligible taxpayers with incomes of over $50,000 were awarded $41,993,000, or $143 per claimant. These figures look even worse when we give effect to the fact that far fewer poor people apply for such credits in the first place. About one-half of the individual returns are filed by people with adjusted gross incomes of less than $12,000. These people received $52 million in tax credits. The upper half of the population received 10 times that amount--$520 million.[3] So beware of the distributional questions raised by continuation or extension of the use of tax credits.

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[2] Data available on request. This conclusion differs sharply from some studies claiming a great future for solar energy. In Solar Energy in America's Future (Stanford Research Institute, March 1977), for example, the authors calculate the cost of solar hot water heating compared to alternatives and conclude "that an economically rational consumer should prefer solar water heating." (page 15) The study does not lay out the details of the economic calculations that lead to this conclusion, but it does indicate that they assumed a solar fraction of 70 percent and a capital cost of $1,100-$1,400 (1977 dollars). Accounting for inflation to bring these figures up to 1980 dollars gives a capital cost of $1,400-$1,800 per system. At these costs and operating efficiencies solar hot water heating would be economical with an electricity price of about 5 cents per KWH in the absence of tax credits. However, the actual costs reported in our survey of utility data are about 85 percent higher and the solar fraction about 40 percent lower than the figures used in the SRI study.

So we have two, partially off-setting distortions: uneconomic subsidization of new technologies through tax credits to the rich, and uneconomic pricing of conventionally generated energy. This Committee should consider, first, eliminating subsidies for all technologies--no tax credits for solar; no government-subsidized nuclear waste disposal programs; no excessive taxes on coal use; no required environmental protection expenditures that are not cost effective; no special treatment of this or that power source. Second, it should at minimum resist efforts by some utilities, old-line regulators and self-styled proponents of economy-in-government and states' rights to render the Public Utility Regulatory Policies Act ineffective. Do not confuse the silly and intrusive Building Energy Performance Standards (BEPS)--a Washington-knows-best and cost-be-damned program of setting efficiency standards--with the heart of PURPA. The latter consists of provisions to encourage state regulatory bodies and utilities to consider more economic pricing of gas and electricity, and of support for FERC data-gathering efforts with similar rate reform objectives.

The combination of an end of subsidization with more rational pricing should produce an optimal mix of research and development efforts--or, at least, one closer to optimal than nuclear advocates, sun worshippers or DOE's bureaucracy can devise.

2. Avoidance of the avoided cost standard. As you know, federal statutes and FERC rules have combined to set a standard for the purchase of

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[3] Data derived from Internal Revenue Service, "Statistics of Income: 1978 Individual Income Tax Returns, Preliminary," Table 8, pp. 42-45.

power from small producers by utilities: the avoided cost. That is, utilities are to pay cogenerators, developers of small hydroelectric sites and wind machines a price for their energy equal to the costs the utilities save by not having to produce that energy. As one of my colleagues has put it:

> In theory, all that is required is for utilities to offer potential cogenerators a price for their energy which is equal to the costs the utilities save by not having to produce that energy--the utility's "avoided costs." Potential cogenerators, acting in their own self interest, will make available to the utilities the amount of energy which they can produce at a cost equal to or below the utility's price. The utilities and their customers are no worse off than they would have been without the electricity from the cogenerators. In addition, society is better off because fewer resources are required to obtain the electricity from the cogenerators than would be used if the utility had to supply that electricity."[4]

But, as Dr. Parmesano goes on to point out, practical problems remain. Utilities are basically conservative and always fearful of unreliable power sources; they have little experience with independent power producers. And utilities have learned from experience that regulators feel under no compulsion to treat them with anything a sane person could characterize as fairness: the danger of being made to buy dear and sell cheap is ever-present.

Small power producers also contribute to the problem. They want to charge avoidable cost but only so long as it is computed at a level that yields them a satisfactory (25 percent?) return. And they want to be paid not only for energy they may provide, but for capacity, whether or not it is reliably and effectively available.

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[4] Hethie Parmesano, "The Case for Cogeneration and Electric Utilities' Response." Comments at a Conference on Real Estate Development with On-Site Cogeneration, New York University, April 6, 1981.

Faced with these conflicting pressures, regulators do what they do best: nothing. How then, can you help to get the show on the road? Keep in mind that what we are trying to accomplish is to get all parties to act in their own interest--cogenerators to make money, utilities to save money, regulators to provide fewer rate increases.

Utilities are becoming more cooperative: building new generating facilities is now seen by most as a necessary evil, an event to be avoided if at all possible. Cogenerators are learning that persuasion and negotiation are more fruitful than an adversary relationship. What this Committee might do is:

a. Make certain that FERC fairly enforces its own rules, bending them to favor neither one party nor another.

b. Urge state regulators--I apologize here to those who feel that such urging conflicts with states' rights--to hold generic hearings to set state-wide avoidable cost levels, and to provide for the flow-through of the cost of such purchases.

c. Remove the restriction that limits utilities to a minority share of any cogeneration project.

These steps should remove most existing institutional barriers to the development of small power sources. While it would be a mistake to give utilities a legal monopoly over cogeneration facilities and small power production facilities, it is also a mistake to limit their participation in the ownership and operation of such facilities.

3. Barriers to utility involvement in conservation. Utilities are currently restricted by the National Energy Conservation Policy Act of 1978 as amended by the Energy Security Act of 1980 from directly providing various conservation services. The antitrust concerns underlying this prohibition are

understandable: large utilities might conceivably compete unfairly with small, independent contractors. But those fears seem less a basis for action now than in the past: utilities have no profits with which to "subsidize" other endeavors; and regulators and antitrust enforcement officials are alert to the problem and will be kept so by never-silent contractors and oil jobbers. These authorities can insist that utilities run any such business as a separate entity without either regulatory protection or limitation on profits but subject to standard antitrust rules of the game. If some customers would rather deal with utilities because they will, in contrast to many contractors, "always be around," so be it. Contractors have the offsetting advantage of flexibility and the speedy response time in which small businesses excel. Let them all compete.

In short, the electric utilities should be allowed to compete on the merits with other firms in the conservation delivery business if they feel that they can in fact compete profitably. As I understand it, some gas distribution companies provide services on this basis.

I suspect that many electric utilities will not want to enter the conservation delivery business because they cannot compete effectively with the existing or potential entrepreneurs in this sector. There is no reason to force them to do so. The utility industry may be able to play a "clearinghouse" role, keeping lists of approved contractors or firms that could be provided to consumers. However, if utilities are to bear any legal liability from such recommendations they will have to be given considerable leeway to decide who gets listed and who does not. There may be good reasons to place utilities in this "agency" relationship with consumers primarily because there are no other obvious institutions to provide such services; but the competitive problems are not trivial.

In sum, we should eliminate any restrictions that keep electric utilities from participating in one way or another in the conservation delivery business, but these activities should largely be separate business ventures and utilities should not be forced to participate if they have no incentive to do so.

4. Organizational flaws in research and development. A final possible impediment to the development and introduction of new technologies is the organization of the electric and gas industries' R&D programs. Years ago, such programs were run primarily by the industries' suppliers: GE and Westinghouse did the research and recovered its cost in the price of equipment. In 1972 the electric industry decided to control the direction of that research effort more fully by forming the Electric Power Research Institute (EPRI). The gas industry followed suit in 1976, forming the Gas Research Institute. Both organizations are funded by the customers: surcharges on electric and gas bills provide EPRI and GRI with annual R&D budgets of about ~~$100~~ $270 and ~~$70~~ $80 million, respectively.

Since the customers pay for this research, the customers have a right to demand that the funds be allocated to projects that will permit the production and delivery of energy in environmentally acceptable and efficient ways. Whether this is happening is difficult to say: the utilities' traditional reluctance to intrude on "the customer's side of the meter" may be affecting the direction of the EPRI and GRI efforts. Perhaps the time is ripe for a review of those efforts in light of the emerging view of utilities as providers of comfort and services rather than kilowatt-hours and Btus.

Also, there is some evidence that the gas industry may be infatuated with technologies that can produce gas that is salable only if its high cost is concealed by rolling it in with lower cost natural gas. Use of customers' money to finance such rate-increasing R&D certainly warrants inquiry.

These, then, are my few suggestions:

1. Support economic pricing of energy by continuing the PURPA program and eliminating subsidies.

2. Encourage economic cogeneration and small power production by enforcing the avoidable cost rule, with a flow-through of purchased power costs, and by allowing utilities freely to invest in such projects.

3. Remove barriers to utility involvement in conservation, so that they are free to enter such businesses if the incentive seems adequate.

4. Re-examine the structure and direction of consumer-funded research and development programs being conducted by EPRI and GRI.

Mr. **Fuqua**. Thank you very much, Mr. Stelzer. Now we'll hear from Jay Kennedy.

STATEMENT OF DR. JAY B. KENNEDY, EXECUTIVE DIRECTOR, ELECTRICITY CONSUMERS RESOURCE COUNCIL [ELCON]

Mr. **Kennedy**. Thank you, Mr. Chairman.

I appreciate the opportunity to be here.

My name is Jay B. Kennedy. I'm the executive director of the Electricity Consumers Resouce Council, ELCON, a group of 16 large industrial consumers of electricity with facilities in most of the 50 States.

ELCON advocates and promotes the development and adoption of coordinated, rational, and consistent Federal, State, and local policies which will assure an adequate, reliable, and efficient electricity supply for all users at prices based on the costs incurred in serving customers.

Mr. Chairman, I think that the topic of financial health of utilities has been pretty well dealt with up to this point, and comment by me would be redundant. We have a serious interest in the financial health of the utilties because of the fact that we depend heavily on their output as input to our production processes.

We are concerned that the financial health of the utilities will result in inadequate capacity sometime after 1990. Errors of that sort are hard to correct, and we will suffer seriously in this country if there is such an electricity shortage. It will affect all companies, and thus many employees throughout the United States.

It seemed to us that perhaps the utility problem is and will continue to be insufficient revenue for the utility industry.

Contrary to Dr. Stelzer's position, we do not think PURPA contributed to the solution of that particular problem. In fact, we think it has been misleading to public service commissions to pursue rate reform when that was not the real problem of the utilities.

Utilities are subsidizing all of their customers. Earnings are insufficient. Therefore, industrial firms, residential customers, and commericial customers are being subsidized by stockholders. That, to us, is the utility problem. PURPA did nothing to deal with that. DOE did not address the subject. DOE did not testify in favor of higher rates of returns for utilities. PURPA was misguided and we hope PURPA suffers the fate it deserves.

Beyond that, we think that there are several important subjects that are before this commitee that you should consider, and they have been referred to today:

One of these is the full-service energy company.

Another is the question of deregulation.

Third, there is the question of alternative technologies.

I noticed in the testimony of Mr. Walker from California, in speeches by the chairman of the California Commission, and from other sourcess that there seems to be a new kind of PURPA attitude prevailing in the Congress. The new view seems to be that the problem of utilities is one that will be solved by some more new remedies, for instance.

I am concerned that the new remedies are somewhat like rate reform. They are mere attempts to avoid the real problem. The real problem is insufficient revenue.

It does not seem to us that full service energy companies will alter the utilities' problem, and it does not seem to us that alternate technologies at the present time offer much hope.

We would suggest that the utility industry be permitted to pursue such goals as cogeneration. We have not fully studied the question of whether they should be qualified cogenerators. Treating a utility as a qualified cogenerator, removing it from regulation, puts it somewhat in the position of a deregulated firm. We're not sure that that's bad. We're not convinced yet that it is an answer that is acceptable to us and to others. You would have a situation in which the utility was selling electricity to itself, but then sold to the public at prices controlled by a public service commission. I think that needs more study.

We also think that the question of deregulation, per se, has not been fully studied. There is no agreed upon definition of precisely what is meant by "deregulation." Some propose to remove from any economic regulation the generating function of existing electric utilities. Under this scheme, the entire generation plant could be sold to one business entity, or each unit in the generation mix could be sold to a separate entity.

St. Lucie 1 and 2 could each belong to a separate company in Florida. I don't know what that would mean to Florida Power & Light. I don't know what it would mean to the customers of that utility in the State of Florida. Presumably this change would not take place on a State basis, but would deal with each utility individually. I don't know for sure.

Alternatively, only new generating plant additions would be unregulated, while existing plants would remain regulated. There are numerous variations on this theme, and no agreement among proponents.

Setting aside the question of implementation of deregulation, the real question is what benefits can be expected if a deregulation plan can be agreed upon?

I offer these observations:

Deregulation has not been proven to offer any benefits over the present structure of the industry. The idea is advanced because it looks like a possible escape from responsibility for good regulation. Some deregulation enthusiasm springs from the belief that nonconventional fuels are not being utilized by the utility industry because of an irrational attachment to conventional fuel sources, and it is presumed that this irrationality will disappear with deregulation.

Earlier, I mentioned some unique characteristics of the electric utility industry. These were, in part, the basis for setting this industry aside for special treatment as a regulated monopoly. Have these characteristics changed? I don't think so.

It is readily apparent that if new plants are built and are not regulated, their output price will be based on their current costs. And that would be a factor pushing electric rates upward. The same result can be obtained under regulation by reevaluation of the rate base.

There is ample experience with the transfer of utility plant from private unregulated service to regulated service. And particularly in Florida, we have experienced that, where water companies were put in by developers and then were transferred to utility service. The Florida Public Service Commission has dealt with the subject for years.

Under such circumstances, the value of the plant is represented by the purchase price of the utility, not its original cost. The financial dilemma of the utility industry is insufficient revenue. This, in turn, is the result of sustained double-digit inflation and the rolling-in problem—new expensive plant added to an original cost rate base.

One must wonder why anyone believes that utility regulators will be willing to raise retail electric rates to reflect the higher cost of power purchased from independent producers of electricity under deregulation, while at present they are unwilling to raise retail rates to these same customers.

Moreover, experience with fuel adjustment clauses in recent years raises serious questions about the willingness of regulators to allow a full pass-through of higher-cost electricity to transmission/distribution companies under deregulation.

As I say, we do not have a full position on this, Mr. Chairman, but the subject is getting important quickly, and I am afraid it may grow beyond its legitimate bounds, through, by enthusiasm for an escape of some sort.

We raise a number of questions in our prepared statement that we think should be answered by anyone proposing deregulation.

On the matter of developing technologies, I am concerned that the California attitude will prevail in the rest of the United States. It's pretty obvious to anyone who has studied the alternate technologies that they do work, whatever that means. However, from a practical and economic standpoint, these sources have severe limitations, including high initial cost, the need for central station backup and possible adverse environmental impact.

Now, we don't have an irrational attachment to a conventional power source. We don't think utilities do either. They will produce electricity as cheap as they can. It's in their interest to do so. We are tickled pink if they do it that way and we are not happy with the thought of having power supplied by windmills to supply an aluminum manufacturing plant. We don't think it's economic, we don't think it's reliable, and we hate to do it just to satisfy the escape mania of some people who don't like the existing utility industry. The risk is too great. There are too many people whose jobs depend on an adequate and reliable supply of electricity.

Mr. Chairman, that concludes my oral remarks. My prepared statement contains additional comments and I request it be included in the record.

[The prepared statement of Mr. Kennedy follows:]

ELCON

TESTIMONY OF DR. JAY B. KENNEDY
EXECUTIVE DIRECTOR OF ELCON
BEFORE THE
SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS
COMMITTEE ON SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES
JUNE 24, 1981

Mr. Chairman and Members of the Subcommittee:

My name is Jay B. Kennedy. I am the Executive Director of the Electricity Consumers Resource Council (ELCON), a group of sixteen large industrial consumers of electricity with facilities in most of the fifty states.*/ ELCON advocates and promotes the development and adoption of coordinated, rational, and consistent federal, state, and local policies which will assure an adequate, reliable, and efficient electricity supply for all users at prices based on the costs incurred in serving customers.

ELCON's founding principles, established to accomplish its objectives, are:

- Electric utility rates should be based on the cost of service;
- Electric utilities must earn a fair rate of return and be able to meet current and future capital needs;
- Federal and state regulatory processes must be responsible and timely;
- Continuing and adequate primary fuel sources for generating electricity should be assured;
- Electric utility costs should reflect efficient operations.

In pursuit of its goals, ELCON has testified at congressional hearings relating to the Public Utility Regulatory Policies Act of 1978 (PURPA), before the Federal Energy Regulatory Commission (FERC), and in many state regulatory rate proceedings. A list of my appearances before state regulatory commissions is attached. Additionally, ELCON staff members have spoken at major electricity conferences and have prepared and circulated numerous reports and other documents relating to rate design, costing, and other matters of importance to the electric utility industry.

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*/ ELCON members are: Air Products and Chemicals, Inc.; Airco, Inc.; Anheuser-Busch Companies, Inc.; Armco; Diamond Shamrock Corporation; E.I. du Pont de Nemours & Company; FMC Corporation; General Motors Corporation; Kaiser Aluminum & Chemical Corporation; Linden Chemicals & Plastics, Inc.; Monsanto Company; Nabisco, Inc.; Olin Corporation; PPG Industries, Inc.; Stauffer Chemical Company; Union Carbide Corporation.

ELCON's members consume approximately ten percent of all electricity sold to industrial customers and nearly five percent of all electricity sold in the U.S. Because of our members' use of electricity, ELCON has a significant, continuing interest in the electric utility industry. We appreciate the opportunity to appear before you.

Our testimony today first addresses the financial health of electric utilities. Comments are then offered regarding several proposals for institutional and regulatory reform mentioned in your letter of invitation.

We do not propose specific federal legislative changes, although legislative initiatives may later prove to be necessary. If legislative proposals are introduced, we would be pleased to offer comments at an appropriate time.

The Financial Status of Electric Utilities

Our country is in the midst of an era characterized by insecure and expensive energy supplies, unsettled capital markets, soaring inflation, and a legacy of over regulation. These factors have created tremendous financial demands on utilities causing bond downgradings and sales of stock at substantially below book values.

While most businesses have been negatively impacted by the economic factors cited above, ELCON recognizes that certain characteristics unique to the electric utility industry may warrant special consideration:

1. Electric utilities provide a unique service. Electricity is not available from other suppliers. It is delivered directly into the customer's home or business. Since there are no alternative suppliers, the utility is essential and irreplaceable.

2. Electricity shortages hurt everyone. In our industrialized nation, users of electricity are interdependent: a power shortage for industrial firms translates into inconvenience and economic damage to workers, suppliers, and residential customers. This threat is unnecessary and intolerable since overcapacity in the utility industry is less expensive to society than is undercapacity.*/
3. The impact of high interest rates and even more rapidly rising energy prices hits utilities harder than industry in general. The capital intensity of utilities requires some $3 to $4 for every $1 in revenue, and the percentage of that capital represented by debt is much higher for utilities than for most other businesses. Long-term debt, of course, carries fixed interest rates. Eventually, however, long-term debt must be rolled over; even in no-growth situations, some assets must be replaced. Quite aside from the growth issue, the changing mix of fuel prices sometimes makes it economical to convert, or perhaps even scrap and replace, plants burning one fuel with plants utilizing less expensive fuels. This reduces the total cost of operation and lessens the risk of supply interruptions (substituting coal or nuclear generation for oils as an example). Such shifts require large amounts of capital.
4. Utilities can change prices only when permitted to do so by state or local regulatory bodies. On the other hand, unregulated businesses have pricing discretion, although this discretion is constrained by market forces.
5. Utilities are required to serve all customers — both the amount demanded and at the time that it is demanded. Alternatively, other businesses may refuse to serve certain customers if that service would be unprofitable.

The pressing question it seems to me is what impact does the financial circumstances of the electric utility industry have on its ability to provide reliable electric service?

Currently these appears to be adequate capacity in the electric system even though there are some areas that have less than adequate reserves. The concern is that present financial difficulties will affect the availability of capacity in the years after 1990 since the time to get a generating unit on line is from 10 to 12 years.

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*/ See the study "Users Guide to the Over/Under Capacity Planning Model," Electric Power Research Institute, Palo Alto, California, Study No. 1117.

A study by the United States General Accounting Office indicates that up to about 1990 we should have adequate reserve margins.*/ The likelihood of adequate capacity after 1990 depends on the rate of increase in the demand for electricity as well as the rate of new plant construction. Poor financial health for the industry may force reduced construction and guarantee insufficient capacity in the future.

Furthermore there is a need for a shift in generation fuels from oil and gas to coal and nuclear. These shifts and conversions cannot be made by an industry that is unable to attract capital on a reasonable basis or perhaps unable to attract capital at all.

ELCON offers the following suggestions to improve the financial health of electric utilities:

1. Avoid sweeping federal responses to problems of utilities. State regulatory authorities should continue to have the major responsibility for regulating utilities. If the performance of some state bodies is not satisfactorily balancing the needs of consumers with the needs of the utilities, efforts should be toward improving the quality of state regulation, and not toward an overlay of federal authority. We reject the concept that coast-to-coast uniformity is inherently desirable.

2. State regulators should be encouraged to act responsibly in regard to the revenue requirements of the regulated utilities. Utilities need an adequate rate of return on a reasonable rate base. No amount of rate reform, no accounting adjustments or other bookkeeping generics can substitute for the realization of this need.

   In this regard, federal regulatory authorities and directives need to be re-evaluated and reduced. State commissions have been misled in recent years by the implementation of the Public Utility Regulatory Policies Act, with the false hope that certain rate reform steps would provide a panacea or quick fix to rate problems. As is now abundantly clear after three years of PURPA implementation, the Department of Energy does not have solutions to the problems of utilities or users.

3. If, after generally accepted regulatory practices have been demonstrated to be inadequate, ELCON believes that certain regulatory procedures could be re-examined in the light of the current financial health of utilities. Tried and proven principles should not be dismissed. We do not propose dramatic changes in traditional regulatory procedures. However, in view of conditions affecting utilities, we submit the following suggestions:

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*/ "Electric Powerplant Cancellations and Delays" U.S. General Accounting Office, Washington, D.C., Study No. EMD-81-25, December 8, 1980.

- Regulatory authorities might consider the use of a fully-forecast test year consisting of the year that the new rates will be in effect, so as to give the utility a fair opportunity to earn the rate of return authorized.

- Regulatory oversight of automatic adjustment clauses should be maintained. However, PUC's should be sure that these clauses are designed so as to minimize the earnings erosion due to fuel cost increases and thus protect the utility's vital cash flow.

- Efforts should be made to reduce regulatory lag while still protecting the rights of consumers to participate in regulatory proceedings.

- Recently, many utilities have found that it is impossible to rely on traditional methods to finance very large construction programs. Inadequate coverage ratios may preclude sale of additional debt while equity shares are sold below book value. Such circumstances must result in capital costs higher than necessary and rates to customers that reflect those costs. When such situations are encountered, local regulatory bodies first should reevaluate the utilities' overall rates of return (both authorized and actual) to be sure that they are reasonable. If after a careful, case-by-case investigation it is determined that strict adherence to traditional accounting procedures is in the best interests of neither the utility nor the consumers, consideration should be given to the inclusion of some or all "construction work in progress" (CWIP) in the rate base without corresponding offsets in the form of allowance for funds used during construction (AFUDC).

- Both state and federal authorities should examine existing statutes to determine if these act as barriers to innovative changes in the structure of the utility-customer relationships. For instance, would ownership of utility generating capacity by industrial firms ease the financial burden of utilities?

4. State and federal authorities should refrain from expanding the scope of electric utility responsibilities. This is true whether the expanded operations are designed to address social inequalities by income redistribution or whether they simply constitute an attempt to promote a particular program or activity. For example, utilities have no special expertise in insulation or consumer loans. Yet programs mandated by the Federal government and implemented by the states require them to enter markets already served by unregulated businesses with that expertise.

5. Finally, our country is in the midst of an era characterized by insecure and expensive energy supplies, high interest rates, soaring inflation, and restrictive governmental policies. Before accepting short-term solutions to these problems, time should be allowed for President Reagan's Economic Recovery Program to have an effect. To the extent that this Program lowers inflation and interest rates generally, electric utilities will find their financial health improved.

Full-Service Energy Companies

It is assumed by some observers that substantial change in the structure of the electric utility industry will solve the "utility problem." I would like to examine several of these proposals.

The first is called the "Energy Service Company Option." This proposal has been propounded by the President of the California Public Service Commission, Mr. John Bryson, among others. He suggests that because of "changed energy economics" or "new energy economics" utilities should expand their scope of operations to supply-side areas such as new generating methods and to demand-side areas such as home insulation.*/

As an economist, I cannot help but challenge President Bryson's premise that "economics" have changed. Certainly utility costs have risen significantly in recent years and utility prices have tended to march upward, but that does not represent a change in economic concepts.

In any case, it escapes me why a full-service energy company is going to be better than an electric utility that does its traditional job while other private companies such as insulation contractors do theirs. Implicit in the full-service energy company proposal is a wish that such a company will "expand by integrating backwards to secure new fuel supplies and by developing and operating new decentralized supply technologies such as cogeneration facilities and other small scale power sources."

Why does the industry need to be restructured to permit the use of new decentralized technologies? Utilities use the least cost method of meeting a forecast load on their system (except for those states that do not permit nuclear or coal plant construction such as California). If wind is an economical source of power and sufficiently reliable, why would a utility refuse to accept it as an option? Utilities are not prohibited from cogeneration. Utilities are not prohibited from adopting small scale power sources -- although I'm glad they choose large efficient ones.

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*/ See "Energy Utilities: The Next Ten Years," remarks by John E. Bryson, President, California Public Utilities Commission, before the California PUC's Second Symposium on Energy Utilities, Stanford, California, March 27, 1981.

The "full-service" idea appears to present two alternatives:

1. A regulated conventional utility that is permitted or forced to integrate forward and backward and where all such activity is under the umbrella of conventional regulation.
2. A regulated conventional utility that is permitted to integrate forward and backward and where all such further integration is unregulated; i.e., outside the scope of state regulatory authorities.

Both of these are currently being practiced. Utilities do own coal mines, barges and other fuel-related properties. Most of these properties are not under utility regulation and I see no reason why they should be. The regulated and unregulated portions of the business should be performed by distinct and separate corporate entities. This further requires that utility funds not be used to finance unregulated, nonconventional utility operations.

I see no reason why electric ratepayers should become investors in speculative ventures such as oil and gas exploration. This does not mean that utility stockholders cannot create subsidiaries to explore or develop fuel sources. If such ventures are successful the subsidiary has the right to dispose of its product to any buyer it chooses — including its utility parent. Then the Commission's responsibity begins: Is the price at which the fuel is transferred reasonable?

I think this Subcommittee, as well as other government officials, should be skeptical regarding suggestions that a conspiracy is afoot to keep biomass, wind, solar and other exotic sources of energy from being utilized more fully by utilities.

There is no such conspiracy and fear of such a conspiracy should not be the basis for restructuring the industry into full-service energy companies, forced to adopt uneconomic technologies or fund end-use programs that function to redistribute income.

Deregulation

A second suggestion that has been advanced recently for restructuring the electric utility industry is "deregulation" of utilities. Unfortunately, there is no agreed upon definition of precisely what is meant by deregulation. For instance, some propose to remove from any economic regulation the generating function of existing electric utilities. Under this scheme, the entire generation plant could be sold to one business entity or each unit in the generation mix could be sold to a separate entity. Presumably, this would not take place on a state basis but would deal with each utility individually.

Alternatively, only new generating plant additions would be unregulated while existing plants would remain regulated. There are numerous variations on this theme, and no agreement among proponents.

Setting aside the question of implementation of "deregulation," the real question is: What benefits can be expected if a deregulation plan can be agreed upon?

I offer these observations: Deregulation cannot be proven to offer any benefits over the present structure of the industry. The idea is advanced because it looks like a possible escape from the responsibility for good regulation. Some deregulation enthusiasm springs from the belief that nonconventional fuels are not being utilized by the utility industry because of its irrational attachment to conventional fuel sources and it is presumed that this irrationality will disappear with deregulation.

Earlier I mentioned some unique characteristics of the electric utility industry. These were in part the basis for setting this industry aside for special treatment as a regulated monopoly. Have these characteristics changed? I don't think so.

It is readily apparent that if new plants are built and are not regulated, their output price would be based on their current costs and that would be a factor pushing electric rates upward. The same result can be obtained under regulation by revaluation of the rate base. There is ample experience with the transfer of utility plant from private unregulated service to regulated service. Under such circumstances the value of plant is represented by the purchase price of the utility, not its original cost. The financial dilemma of the utility industry is insufficient revenue. This, in turn, is the result of sustained double-digit inflation and the rolling-in problem -- new expensive plant added to an original cost-rate base.

One must wonder why anyone believes that utility regulators will be willing to raise retail electric rates to reflect the higher cost of power purchased from independent producers of electricity under deregulation, while at present they are unwilling to raise retail rates to these same customers. Moreover, experience with fuel adjustment clauses in recent years raises serious questions about the willingness of regulators to allow a full pass-through of higher cost electricity to transmission/distribution companies under deregulation.

Although ELCON has not yet developed a position on deregulation, we believe that considerable thought and study must precede any decision to separate the utility generation function from the other traditional electricty functions. We list below some other areas of concern that we think should be addressed prior to the implementation of any deregulation effort:

1. How would deregulated generating companies be able to coordinate their operations to assure an adequate and reliable supply of electricity and yet not engage in anti-competitive collusive behavior. This is not a mere aside. Real problems must be solved by doers, not speculators.

2. After deregulation, would a sufficient number of independent companies exist to assure that the benefits of competition are achieved? Alternatively, are the conditions of the industry such that the end result would be a monopolistic generating company selling to a monopolistic transmission/distribution company?

3. How would the problems of wheeling be addressed in a deregulated context? More basically, couldn't many of the alleged benefits of deregulation be achieved through more liberal wheeling and/or a relaxation present sale-for-resale restrictions? If so, shouldn't this regulatory option be seriously considered?

4. Would deregulation result in nationalization of certain aspects of the electric utility industry?

5. Would deregulation effectively reduce the authority of state regulatory bodies by requiring them to pass through price changes not under their control?

6. What assurances would be provided that adequate capacity would be built? Could sufficient capital be raised to allow the construction of expensive coal and nuclear plants? Would the capital costs of companies engaged only in generation be higher than the capital costs of vertically integrated electric companies?

7. What would happen to the existing concept of an "obligation to serve."

8. Is deregulation the offspring of utility opponents and alternate energy source proponents who see the demise of the generating function as the vehicle for pushing solar, wind, biomass, etc. regardless of economic feasibility?

We call the Subcommittee's attention to this partial list to highlight our concern about a rush to deregulation based on a perhaps misguided notion that it would solve the financial problems of the electric utility industry.

Developing Technologies

In your letter of invitation, the Subcommittee expressed interest in changes in the electric utility industry that might facilitate or impede the market acceptance of developing technologies. ELCON believes that alternative energy concepts cannot play a significant role in the overall U.S. energy balance prior to the early years of the 21st century. The problem is not just market acceptance, nor is it utility narrow-mindedness! Technological and economic limitations restrict these exotic technologies.

Our nation will increasingly depend on electricity and serious questions arise as to whether the electric industry will be able to satisfy future electricity demands. The Energy Information Administration (EIA) of DOE projects that electricity will be called upon to satisfy more than one-fifth of all end-use energy consumption in the year 2020, with more than 80 percent of that year's electricity supply projected to come from coal and uranium.*/ Thus, EIA is projecting electricity to represent nearly twice the proportion of end-use energy consumption that it now entails.

Solar and other renewable sources (wind, photovoltaic, hydroelectric, ocean thermal energy conversion and tides, biomass, and direct thermal solar) are technically feasible alternative electricity sources. However, from a practical and economic standpoint, these sources have severe limitations, including high initial costs, the need for central-station backup power, and possible adverse environmental impacts.

While some of these energy sources are, or will be, viable for small power generation in selected applications, ELCON does not foresee a significant contribution by any of them to the national electric power pool before the beginning of the 21st century. ELCON is not philosophically attached to conventional generating facilities. It is simply a fact that the exotic, untested energy sources cannot be expected to solve the nation's near-term energy needs. Reliance must be placed on existing electric generating technologies — particularly coal and nuclear power plants — to satisfy electricity demands for at least the next 20 years.

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*/ 1980 Annual Report to Congress, U.S. Department of Energy, Energy Information Administration, Washington, D.C., Volume III, pages 123-124.

ELCON is concerned that economic and environmental constraints are limiting the construction of new coal and nuclear electric generating facilities. An insufficient number of coal and nuclear facilities can negatively impact the adequacy and reliability of our nation's electricity supply.

ELCON strongly supports efforts to eliminate regulations that are unnecessary and not cost-justified. Environmental restrictions should be examined carefully to reestablish their need. While waste products from nuclear facilities are being stored satisfactorily on an interim basis, permanent disposal methods must be established. Licensing and construction of coal and nuclear power plants should be accelerated.

Conservation

In closing, I would like to comment briefly on conservation — sometimes cited as a cure-all to the electric industry's problems. ELCON's member companies strongly support energy conservation and have made substantial investments for that purpose. The combined efforts of industry and homeowners have slowed the rate of growth of national energy usage and have caused per capita energy consumption to decline. But we have serious reservation about existing government programs that attempt to mandate conservation.

Those who emphasize conservation claim that it is less expensive and less risky to implement conservation measures than to build new power plants. They often urge establishment of conservation programs administered by regulated public utilities.

Over the past several years, several legislatures and state regulatory authorities have considered, and in many cases are implementing, a variety of programs, first in response to recommendations by those who emphasize conservation and later in response to federal mandates contained in the National Energy Conservation Policy Act (P.L. 95-619) as amended by the Energy Security Act (P.L 96-294). These laws require utilities to offer energy conservation information, on-site energy audits, and — for residential buildings — information on arranging the supply, installation, and financing of conservation measures. The statutes prohibit the full cost of these services from being recovered directly from the building owner or tenant who receives the benefit.

Conservation programs resulting from these statutes seek to promote conservation by providing financial aid to customers who may benefit from conservation investments but have not made them on their own. Under such programs, the cost of the financial aid must be shared by all customers on the theory that conservation will reduce the cost of a utility's current and future operation. It is assumed that when costs go down, revenue requirements will decrease, and all customers will realize benefits in excess of costs.

In practice, all customers may not benefit from government mandated conservation programs and even if they did, they would not do so equally. For example, the direct and immediate benefits from energy and demand conservation obviously flow only to those who participate in a program. Non-participants would not receive any direct, immediate benefits. It should be particularly noted that all residential customers who have made prior independent investments in conservation, as well as most industrial and commercial customers, will be non-participants but will be required to bear the cost of conservation investment for others.

The primary benefits claimed for non-participants which would, of course, accrue equally to participants, are savings associated with the possible delay in the construction of future capacity. The saving is highly uncertain because it depends upon an uncertain amount of load reduction, it may not be in the customer's best interest, and the delays may occur too far in the future to have any real meaning today.

ELCON has carefully considered conservation programs. We strongly support the goal of conservation, but we do not think that electric utilities are the best vehicle for achieving the desired results. However, since existing laws specify involvement by utilities in residential, commercial, and multifamily conservation programs, the specifics of the programs should comply with basic utility principles.

1. Programs should require that each approved investment must generate benefits in excess of cost to yield acceptable returns.
2. Programs should allocate all costs to the customer classes, and preferably to individual customers, in proportion to the benefit received.
3. The methods to allocate costs should be established and revised only after public notification and review.
4. Programs should be structured so that all costs and benefits are adjusted for their risk and timing because future costs and benefits have relatively less value than current costs and benefits.

Conclusions

- In order to provide an adequate and reliable supply of electricity, the electric utility industry must be financially healthy. Electricity serves a large and increasing portion of America's energy needs. Increased use of electricity should accompany our shift from oil to domestically abundant coal and nuclear fuels. Breakthroughs in alternative technologies will not change this picture for many years to come.
- Authority to regulate retail utility practices and rates should remain at the state level. Regulation must be sensitive to conditions peculiar to the local service area, such as: local fuel costs and fuel mix, local construction costs and tax policies, customer mix, and climatic conditions. Federal

standards cannot value these peculiar circumstances with the necessary sensitivity. Regulatory decisions made in New York may be inapropriate for Florida or Texas or Oregon.

- The electric utility industry should remain investor-owned. The problems facing the industry are not attributable to its ownership. It should be clearly recognized that public ownership of some railroads (e.g., Conrail) has not cured the railroad's problems. Similarly, the publicly-owned Tennessee Valley Authority (TVA) faces many of the same problems investor-owned electric utilities face plus some special public ownership problems.

- Electric utilities are not the best vehicles for achieving desired conservation results. Since existing laws specify involvement by utilities in conservation programs, the specifics of the programs should comply with basic utility principles.

SUMMARY

APPEARANCES BY DR. JAY B. KENNEDY BEFORE STATE REGULATORY AUTHORITIES

STATE	CASE	SUBJECT	TESTIMONY PRESENTED
Alabama	PSC Doc. #17859, Alabama Power Rate Case - Phase II	PURPA Section 111 Standards only	4/30/80 Montgomery
California	Los Angeles Department of Water & Power	PURPA Section 111 Standards	3/3-4/80
	LADWP	Lifeline	3/12/80
	Santa Clara City Council	PURPA	5/12/81
	Southern California Edison - PSC Doc. #59351	PURPA	6/10/80 Los Angeles
Connecticut	PUCO Generic	PURPA	6/30/80
Delaware	PSC Doc. #923 - Delmarva	PURPA Section 111 Standards only	Testimony filed but no direct required.
Florida	PSC Doc. Nos. 790571-EU & 780793-EU	PURPA Declining Block Rates	12/20/79
		PURPA Time-of-day Rates	1/25/80
	PSC	Lifeline	10/23/80
Georgia	PSC Doc. #30[illegible]7-U - Georgia Power	Generic Rate Hearings	6/27/78

STATE	CASE	SUBJECT	TESTIMONY PRESENTED
Idaho	Idaho Power & Light	PURPA (Cost of Service)	12/18/80 Boise
Illinois	Commonwealth Edison	PURPA	3/6/81
	Illinois Power	PURPA	3/11/81
Kentucky	Jt. Interim Committee on Public Utilities Transportation & Kentucky Energy Regulatory Commission, Admin. Case #202	Lifeline	8/29/79
	PSC CASE #203(b)	Cost-of-Service	4/29/81
Louisiana	New Orleans Public Service, Inc. Rate Case	Section 111 Standards and Lifeline	1/13/81 New Orleans
Maryland	PSC Case #7159, Baltimore Gas & Electric	PURPA Section III Standards	4/10/80
	PSC Case #7456, Baltimore Gas & Electric	Lifeline	5 /14/81
Minnesota	PSC Doc. #E-862/M-78-753	Review of NSP Electric Rate Structure (FEA Pilot Demonstration Project)	10/18/78
Missouri	Kansas City Power & Light	PURPA Section 111 Standards	2/18/81
Nevada	PSC	Cost of Service	12/2/80 Las Vegas
	PSC	Lifeline	12/11/80 Las Vegas

STATE	CASE	SUBJECT	TESTIMONY PRESENTED
New York	PSC Case #27344 - Orange & Rockland Utilities	PURPA Section 111 Standards	9/17/79
North Carolina	Utilities Commission	PURPA Section 111 Standards	Testimony filed and decision made not to testify because no cross-examination was available.
South Carolina	PSC Doc. #79-196-E, South Carolina Electric & Gas Co.	PURPA Section 111 Standards	No
	Duke Power	PURPA Section 111 Standards	7/18/80
Tennessee	TVA PURPA Hearings	PURPA Section 111 Standards only	3/11/80 Memphis
Texas	PUC Doc. #1776	Generic Rate Review	5/22/78
Virginia	VEPCO Rate Case	PURPA Section 111 Standards	2/24/81
Washington	W.U.T.C. Case #U-78-05	Generic Review	1/23/80
	Clark County P.U.D.	Section 111 Standards and Lifeline	Testimony filed, but no appearance required.

STATE	CASE	SUBJECT	TESTIMONY PRESENTED
West Virginia	PSC	Lifeline	7/2/80
	PSC Case #79-140-E-42T Appalachian Power Company	PURPA Section 111 Standards	5/5/81
Wisconsin	PSC Case #6630-ER-10	PURPA Section 111 Standards	2/26/80
Wyoming	Pacific Power & Light	MCP/Cost of Service only	12/1/80 Laramie

Mr. FUQUA. Thank you, Mr. Kennedy.

I'm afraid we have another rollcall vote, and we will stand in recess for a few minutes till one of the members comes back and we can start the questions.

Again, I apologize for the inconvenience.

[Recess.]

Mr. DUNN [presiding]. We'll call the meeting back to order, unaccustomed as I am to being chairman.

Let me start the questioning by saying that we have been talking about diversification, and I guess I would call it more a move to a more full service line for the utility companies. But in looking in that direction, there are several different ways company can go. One of them is indeed to procure the different elements in that, as suggested by the gentleman here. But rather than actual procurement, what would be wrong with other types of intermediate steps, which we haven't talked about—direct contracting sales and lease back?

Mr. Nichols, could you answer for me? In looking at the companies where you have a cash flow problem, sale lease back or direct contract with a shipping company for a long term might seem to give you the advantages of both without tying up the same amount of needed cash.

Mr. NICHOLS. We have looked at sales and lease back possibilities, but in all of our diversification efforts, we do our utmost to do it with a minimum amount of new common equity. But, frankly, sale and lease back arrangements usually wind up with some one else getting many of the benefits—the tax benefits and/or the earnings. Thus there is a little or no value to this kind of diversification.

Mr. DUNN. In terms of immediate cash flow problems, it would seem, rather than sinking a large amount of money into it, that would be a way out of it.

Mr. NICHOLS. That could be a way out, but not neccessarily an attractive way. Why take on additional risks if you're not going to get additional benefits?

Mr. DUNN. Mr. Stelzer.

Mr. STELZER. Certainly, there are some benefits. Some have sold their office buildings and leased them back, and some have sold coal properties and have leased them back.

I think what you're essentially trying to do, when you think about these things, is to buy a pair of rubber gloves for a leaky fountain pen. It's not the optimal solution. The fundamental problem is that the utilities don't have earnings.

Now, you can sit around and think of lots of ways an enterprise can operate without earnings. It can sell its assets and lease them back. It can try a lot of things, but you're not going to solve anything until these companies get some earnings. And sale and lease back is a temporary palliative.

Certainly, some companies can do it, and some are doing it. Diversification has some long-run attractions to it, but basically it's a sign of the desperate man who can't make money in a business he's ordered to stay in and ordered to serve at.

And until you solve that problem, you can look to the sun for solutions, you can look to the wind for solutions, you can look to lease backs for solution, and you can look to diversification, but you're not going to find the solution. How you solve the problem, I don't know. I despair about the regulatory process.

I have appeared before rate regulators all over the country, and basically it's a disastrous situation, to which I see no ready solution. For example, in some States utilities are steadily deteriorating the quality of service with terrible consequences for the country; the utilities are forced to find other industries in which to make money. I think that's sad, and unfortunately I don't have an answer to it. I don't think lease backs are an answer to that.

Mr. DUNN. You raised the point of lack of return for investors in the utility companies, and I asked the same question yesterday: Is there any fiscal policy we can use—and I don't really know of any—to raise that investment capital when looking at a new plant? And he went right back to your same scenario, that regulations were the big part of it.

Mr. STELZER. First, Congress has to bite the bullet of States' rights. You have to say:

> Are we willing to interfere with a state's regulatory process? Do we have a national problem here of excessive reliance on imported oil? And are there, here, the contours of a national problem?

If the answer is yes, you believe there is a national problem, then the solution is national. Then you're going to have to step all over some State regulators.

If you cross that bridge and are willing to step on the toes of State regulators, there are things you could do. These companies, for example, could have what is called contruction work in progress put in the rate base by mandate of some Federal regulator, in pursuit of some national objective; they would be better off, of course, if they were actually permitted to earn the returns set by State regulators.

As Mr. Swidler pointed out, they would be better off if State regulators stopped saying utilities are "allowed" to earn 16 percent on equity when they know actual earnings will be 12 per cent. But at this point, Congress is unwilling to intrude in the State regulatory process. And since I'm against subsidies—I don't think you should subsidize even my friend Mr. Nichols—all you can do is keep continuing pressure on FERC to explain how its programs are consistent with a national policy of getting off oil and with a policy of economic growth. For while there is much talk about decoupling economic growth from use of electrical energy, and while the relationship is not as great as it used to be, the fact is that since the Arab oil embargo, the growth in the use of electricity has exceeded the growth rate of real GNP. So you can keep the heat on FERC, and you can keep PURPA in order.

I would resist, if it were me, various of the tax goodies that people want. I think you have to have a policy to make it more attractive for all to invest in equities. But other than that, there are not a lot of things you can do.

Mr. DUNN. I can relinquish the chair back to the chairman. One more question while I'm doing that though: Mr. Nichols is indeed involved in purchasing coal and oil. Do you think the increased speedup of the deregulation of natural gas is a good idea?

Mr. **Stelzer**. I think it's a good idea. It, sooner rather than later, gives consumers the right signals as to what they should use. It makes more economic new technologies in which you are interested. By deregulation I mean—let the price go up and also get the restrictions of the Fuel-Use Act out of the way so that electric utilities can make their own decisions as to what fuel to burn and what is cheaper for their customers. That would be a big help. It would relieve a large uneconomic, irrational capital burden.

Mr. **Dunn**. When you say a big help, a big help to who?

Mr. **Stelzer**. A big help to the gas-burning utilities, who are being forced to spend huge amounts of capital to convert from gas, when gas may indeed be the most economical fuel for them for a very long time to come, and hence to the customers of these utilities.

Mr. **Dunn**. Where does the consumer benefit in the end? He benefits, but if we speed up deregulation of natural gas, how do we get over the catastrophic effect of seeing the bill double? How do we handle that?

Mr. **Stelzer**. Well, I think if we agree that the place to get to is a deregulated set of prices, and if you are concerned about the jarring transitional effects of doing that and only concerned about that, I would think you would be much better off to let the consumer get the right price signal, and then if you want to give a certain tax advantage to the consumer, do that.

For example, gas companies are taking on new customers. I was out in Peoria, Ill., and they're taking on 10,000 new customers. It's a wonderful thing. Those customers think gas is really cheap. And, boy, are they in for a terrible surprise soon. Now, I would rather have them know the price at the time they pick what fuel they're going to use, because you're sucking more people in every day into using what they think is cheap gas.

Mr. **Dunn**. You just said you were against subsidies, and now you're proposing subsidies.

Mr. **Stelzer**. I'm saying give subsides to the consumer in order to manage the transition. If you're concerned about the equity problem of jumping a gas bill by double in one winter, you might want to draft something with a means test to identify people who need some relief during the transition period. But to keep the price down and get more and more people getting sucked in, thinking this is a low-priced fuel, seems to me the harshest kind of justice.

Mr. **Dunn**. If we went to deregulation of natural gas right now, in your estimation, how long would this tax subsidy—how many winters are we talking about?

Mr. **Stelzer**. I think you're probably talking about three.

Mr. **Dunn**. Thank you, Mr. Chairman.

Mr. **Fuqua**. Thank you, Mr. Dunn.

Mr. Mitchell and Mr. Nichols, Mr. Stelzer mentioned the relationship of EPRI and GRI. You are not involved in the GRI, but you are involved in EPRI. Do you feel as though they are adequately serving the utilities' needs in their R. & D. work? Are they off on the wrong projects, or are they responding to what you see as the needs of utility industry, say, for the next 20 years?

Mr. **Nichols**. I speak from a biased position, Mr. Chairman, because I'm a director of EPRI. I think EPRI has grown over the past decade. And, as Irwin mentioned, it's annual budget is now in excess of $200 million. I have never known a director of R. & D. that didn't think he could happily and profitably spend twice whatever his budget was. That is just as true of EPRI as it is of our own R. & D. director in our own shop. It is a very difficult area to manage. R. & D. is a challenge.

But, I think that if we have erred at all in our industry, it is we have erred on the side of not spending enough on R. & D. We can always debate are we 100 percent efficient in our expenditures? And I don't think I'm 100 percent efficient in anything.

So, I really think that we have come a long way. I think the continuity, for example, of EPRI R. & D. is particularly critical during periods when Federal R. & D. in the energy area perhaps is on the decline.

Overall, I think EPRI has a lot to offer and is doing a good job.

Mr. FUQUA. Mr. Mitchell, would you care to comment?

Mr. MITCHELL. Well, I would only echo Mr. Nichols comments and just report that in our gasification cogeneration effort, we have just received a lot of support from EPRI Basic Research, particularly in the gasification technologies, which are yet to be proven, you know, on a large commercial scale. So, we have received benefits, and I would agree with Mr. Nichols that it would be impossible to say they're all perfectly expended funds, but I think the benefits are for our customers.

Mr. FUQUA. Mr. Kennedy, I notice the list of people who are members of your organization. Do they buy their power wholesale, direct from the utility? Or are their rates regulated by State regulator agencies?

Mr. KENNEDY. Sir, they buy about 5 percent of the electricity sold in the United States by electric utilities, 10 percent of industrial electricity purchases. And it's bought at retail electric rates, with some possible exception on Federal power marketing agencies, TVA and so forth.

But by and large, the mass of that is bought under regulated rates, regulated by public service commissions.

Mr. FUQUA. There has been some talk today about central station power and whether or not we should disperse or build smaller alternatives. One of the things we are responsible for in this committee is to review DOE budget requests for R.D. & D., some on central station and some on dispersed power sources.

How do you feel—anybody that wants to answer how do you feel about the balance? Are we going in the right direction or should we go in a different direction?

Mr. Swidler, you have been involved in many different facets of that.

Mr. SWIDLER. Well, I have tried to keep in touch with what is going on in industry. I think it depends on what source of power you're talking about—the technology, rather than whether it's central station or dispersed.

Now, most of these dispersed sources are not firm supplies, windmills, solar sources. So far as conventional supplies from small sources are concerned, like the small hydros, I think that the current process for alternative sources of energy are probably economical, many of them. And certainly with all the tax subsidies, they become economical.

The industry has put a lot of money into research on fuel cells, which constitute a dispersed source. One of the problems there, of course, is that so far it depends on natural gas, which is a scarce fuel. The history of fuel cell development has been a rather slow one, in that 20 years ago I was shown a fuel cell just about ready for commercialization, and again 10 years ago. And it just moves more slowly than you would think.

The people in the industry who have responsibility for being sure that when people flip the switch their lights will go on, do not really see a basic alternative to the central station service as yet.

I wonder if I can add a word on the question of the kind of job that EPRI is doing and I suppose GRI, too. I'm on the advisory council of GRI, and I was on the advisory council of EPRI for a number of years and had something to do with the establishment of the predecessor of EPRI.

I think you have to look at the job they are doing in the light of the special problems of the electric power industry and the gas industry.

In the electric power industry, for example, there are 3,000 entities in the industry. They all use the same technology. They are not in a position for one to make an advance at the expense of the others. For a long time the manufacturers did the research. Then they decided the research responsibility was too expensive for them.

Now, EPRI came into being, and GRI also, after the basic responsibility for research had long been in the hands of the manufacturers. They haven't tried to focus it all in their own laboratories. Almost all of it is done by contract. It's not the way the chemical industry or the petroleum industry functions, but it is adapted to the special problems of the electric power industry. And I think, considering that it replaced a situation where nothing much was being done by the electric power industry, that it constituted a very great advance.

Mr. STELZER. Mr. Chairman, may I add something? There is no question that we are ahead of the game with EPRI compared to letting the manufacturers do it. The fundamental question that you might want to think about if you're interested in R. & D., for instance, especially, given the decline in DOE funding of R. & D., is how is EPRI funding integrated with DOE funding? Is it a question of one provides seed capital and the other provides more money, or should they be going in different directions, one concentrating on one area and one on the other?

Don't compare the electric industry only with the chemical industry, but compare it to communications. Do you want contract research on the EPRI/GRI model, or do you want integrated research on the Bell Labs model? I really don't know the answer to these questions. They are extraordinarily difficult questions. But if you are interested in R. & D., you have the resources to begin to ask these questions.

These are big organizations. Like any big organizations, they find a reexamination painful. And the reexamination may prove they're doing wonderful things. But the question is, How do they integrate with Federal programs? Should they be having their own labs and not using contract research? Should they be going into development along the lines of Western Electric and not relying on manufacturers for that?

These are very profound questions as to the structure of research, as is the question of what incentive they have to do research that is in the customer's interest. We are talking about customers' money, whereas in a competitive, nonregulated industry you are talking about stockholders' money. Are EPRI and GRI doing research that is in the customer's interest? Is a big coal gasification plant to make gas at $9 a thousand cubic feet in the customer's interest? I understand why the companies want it, and I understand why scientists like to play with these big projects, but it seems to me these are profound questions which somebody ought to think about.

Mr. FUQUA. Thank you. I certainly didn't mean, when I asked the question, to be critical of either organization. We have had very excellent relations with them.

We have a roll call vote, and we will have to temporarily suspend. Mr. Harkin will be back, hopefully, in a few minutes. Again, I apologize for the inconvenience.

[Recess.]

Mr. HARKIN [presiding]. The subcommittee will resume its sitting.

We seem to be plagued with innumerable procedural votes this morning. I don't know what's going on over there. It seems someone wants to slow down the floor process today for some reason or other.

A couple of questions I had for Mr. Stelzer. I am interested to know to what degree the utilities are actually pursuing conservation, cogeneration and small power production to reduce the need to tie up capital in long lead time central station facilities.

Mr. STELZER. I have a chart I would be glad to submit. I didn't bring it with me. It has conservation programs of various kinds, ranging from energy audits right on through actual installation, and including contractors to customers' homes. My feeling on conservation programs is that the major problem is the customer, not the availability of service. The notion that people will put a conservation investment in their home with a 5- or 6-year pay out is apparently wrong. People have much higher discount rates than that, and they're just not doing it.

We're now doing a study of the energy audits that the utilities did, what they recommended to the customers, and then what the customers did about it. And it's really surprising.

Mr. HARKIN. Have you looked at Pacific Power & Light?

Mr. STELZER. Pacific Power & Light has the most advanced program, and they have been fairly successful. But that's a very special area, because there is a lot of electric heat up there in old houses. You see, in most parts of the country there isn't that much electric heat. Where it does exist, it was put in in very heavily insulated so-called "Gold Medallion" homes, and the margin for saving is really quite small.

Pacific Power Light—and I have been through their program with really great care from its formulation through its implementation—really has a very unique electric space heating situation up there. Now that doesn't mean that I think utilities are doing all they should do. Please understand. There are some that are very skeptical about it. But if you look at the sales of the insulation material, look at the sales of storm windows around the country, you'll see that those industries couldn't produce enough of the stuff to provide to the customers. Customers are smart, and they buy what they need to save back money. But apparently they want much shorter pay-back peiods than we have thought they would feel satisfactory.

Mr. HARKIN. Everybody in America—every family is pinched.

Mr. STELZER. Right.

Mr. HARKIN. Unless you are making $200,000 a year. Maybe even they are pinched, if you estimate their living standards.

Mr. STELZER. Everybody feels they would like to have more. Everybody.

Mr. HARKIN. Whether it's my own family or other households in my income bracket, everybody is feeling the pinch. If you tell someone even in a tax bracket of $50,000 or $60,000 a year, "You ought to put in maybe $400 or $500 of insulation," he will say, "Where am I going to get it? I don't have it. I have to borrow it and I have to pay 18 percent, so it's not worth it." Coming up with immediate cash, is a problem. But if a utility comes along and says, "you insulate your house, we'll pay for it, and we'll bill it into your rate," I'd love to have that happen.

Mr. STELZER. I'm sure you would, especially depending on what they charge you for the interest. A free lunch is always the tastiest.

Mr. HARKIN. No, even if it is 18 percent.

Mr. STELZER. But the question is, where are they going to get the money? Now they're paying, I guess, 17 percent or something like that for capital, and they're earning 14, so where are they going to get capital? If you mean, it would be awfully nice if they would come along with $500 insulation for your home, and spread the cost among all the customers of the system, even those who didn't take the insulation, I'd understand. The question is, what are you trying to get? You can——

Mr. HARKIN. You're trying to get utilities to insulate houses rather than build large central power stations to meet extra demands. It's my feeling, that they would use less capital to invest in getting people to conserve energy in their homes, thereby allaying the need to build extra central power stations.

Mr. STELZER Let me make two comments. There is no utility in its right mind, and most of them are in their right minds—there's no utility in their right mind that wants to build a central station plant.

Mr. HARKIN. There isn't?

Mr. STELZER. No; they don't want to build. Every utility executive I have talked to views the starting of his next plant as the greatest horror of his life, because he's going to have to pay more for capital than he can reasonably earn on it. So they start from a bias of trying to get out of that. What they really want to do is diversify. Second, if, indeed, the customer is better served by conservation than he is by using more energy, the customer will know that.

You are assuming that customers do not have available to them credit, and I think what you are really objecting to fundamentally is the high interest rates. High interest rates are supposed to ration capital, and that's what they are doing, and they're hurting a lot of people, businessmen as well as consumers. As long as you have a Federal Government that is committed to fiscal irresponsibility and monetary restraint and willing to unbalance the budget way the hell and gone in pursuit of I don't know what kind of theory, and put all the burdens on monetary policy and keep interest rates up, you're going to get hurt, and that's what they are planning to do.

So it seems to me that the culprit is down the block and really not the local utility.

My experience in cogeneration, which is the other part of your question, is that the utilities are definitely conservative. They are nervous about the reliability of power from cogeneration or small power production. They are unfamiliar with some of the technology, and they are afraid that the regulator is going to make them buy the power at very expensive prices and not let them flow through its cost. And they have good reason to fear regulators. The proclivity is in that direction.

I think the problem of high interest rates, which is pervasive, is affecting your decision whether to buy insulation. I don't think the utilities have any better access to capital than you do.

Mr. HARKIN. Are there not some incentives now for utilities to seek cogeneration?

Mr. STELZER. There are. And they are doing it. They are doing a lot of it. But they are having difficulty finding cogenerators because, if you are in business and some utility is giving you electricity and earning only 9 percent on his equity doing it, are you going to come along and say, "Gee, I really want to cogenerate. I'm going to build the facility. I'm accustomed to earning 20 to 25 percent on my equity, and my own electricity utility is giving power to me practically free. He's forcing the stockholders to give me capital by selling stock below book value, and he's giving me a terrific buy."

Well, one of the problems of cogeneration is that the utility alternative is to industrial customers, cheap, uneconomic power being provided by the stockholders of the electric utilities in an unwilling subsidy. Now if you could get electric utility rates up to economic levels, I think you would then see a burgeoning of interest in small power production and in cogeneration by outside investors.

Mr. HARKIN. Mr. Kennedy, any comments along that line?

Mr. KENNEDY. Perhaps one or two. First of all, back to the conservation issue. We are concerned about the residential conservation program promulgated by the Federal Government. I think part of the problem stems from a misunderstanding of what conservation is. Conservation in the minds of many people is, simply, "do not use." If more electricity is consumed than some absolute amount, that is believed to be wasteful, or nonconservation. I think that's a poor way of looking at conservation.

I think conservation is one of the alternatives and it is the outgrowth of a rational economic process.

Now, you talk about putting 400 or 500 dollars' worth of insulation in a home. Perhaps you could spend another $5,000 and conserve even more. The basis for that kind of thinking is that you don't want to build a generating plant, whether it is central or dispersed. I think that is the wrong assumption to start with. Building a generating plan is not bad per se, it seems to me. The question is, what is the proper mix between installing conservation measures—that is, insulating your attic, changing your windows, and buying electricity?

At one time in the past, the Federal Government had energy efficiency ratings on appliances, and other devices, and the Federal Energy Administration pushed very hard to have people buy the most efficient appliances. At that time I was with the Florida Public Service Commission. We did a little computer analysis of that issue. The one rule we came up with at that time was that you were always better off financially buying the most inefficient unit. Now that may come as a terrific setback to the idea of conservation. But what people conserve is their income and their wealth. They spend their income in such a way as to maximize thin well-being.

One of the things they can buy is electricity. Another thing they can buy is insulation. I think that the program in California, and certainly the Federal push for conservation programs, smacks of the idea, "Put it in and somebody will pay for it." What we are concerned about very specifically is that industrial customers are going to pay for it.

Now I want to show you how the idea affects us. If insulation is added to all the residential homes in the United States that could use a little more, industrials end up as electrical customers paying for that. And this is no small amount—$500, $800, maybe $1,000 per home. And as Irwin has suggested—and it is true—there is no free lunch. If they are getting it for less than it costs, somebody else is paying for it.

And why is it that utilities should get into the area of insulation? There are competent insulation companies out there. What you are looking for, perhaps, is a financing mechanism. We do not see a reason why the utility industry, if, indeed its financial condition is as bad as it appears to be—should be given the burden of financing other aspects of the business. It seems to me then they have their hands full taking care of business at home.

We have businesses in place capable of insulating attics. We have financial companies capable of lending that money. Why should industrial customers pay for insulating residential homes, especially if we must reflect that in the price of our product? There is no such thing as a free lunch.

Mr. **Stelzer**. Mr. Chairman, the problem you are having is one that some of us who go to hearings not involving energy find all over. There's not enough home building. Why? Interest rates are too high. How can we beat the game? We'll do something that makes them lower for the customer. There's not enough conservation. Why? Interest rates are too high. We'll find some way to make it cheaper to the customer. Savings and loan banks are in trouble. Why? Interest rates are too high. We have got to find some way to subsidize them.

What you have is a dramatic change in the level of interest rates which change is interfering with some people's notions of what ought to be happening in the economy, and you have a groping around in committee room after committee room for a way around this hard fact.

And there is no way around it. The Government is good at creating jobs, but it doesn't seem to be as good at creating wealth. If the Government can find a way to create wealth, then it could do something about these problems.

But otherwise, you're stuck on the horns of a dilemma. You have a utility industry with no money. You have——

Mr. **Harkin**. You have what?

Mr. **Stelzer**. A utility industry with no money.

You have a bunch of objectives of people for conservation and other things which consumers are deciding they can't afford to do. And, what you are trying to do is find some way that the guy with no money can make it possible for the consumer to do things he can't afford.

Now, the bridge—the possible way out—it seems to me, is if the utility industry can save more on central station generation than it spends on buying conservation for its customers. If Pacific Power & Light puts $1,000 into a home, and saves more than $1,000 on what it doesn't have to build, it will do so. Those programs certainly should be employed. But they have to be specific to certain climates and energy use conditions, which are cold, unpleasant climates, basically, with a high incidence of electric heat, and older homes.

Beyond that, there isn't that much to do unless you want to start on the kind of subsidization program that they do in California.

The utilities, I can assure you—I spent years fighting this fight, begging them not to build these plants because they couldn't afford it, and being not cordially welcomed in some circles in the industry because of that advocacy—now are finding that they do not want to build anything.

I have clients who used to have very high reliability standards. They now are designing much less reliable systems in order to avoid building plants. The problem is not that they want to build plants; the problem is that money now costs money, and it costs more than consumers are used to paying, and more than they feel they can pay. That's not a utility industry problem, that's a general economic problem.

Mr. **Harkin**. Any other comments?

Mr. **Nichols**. Mr. Chairman, I would like to summarize some of the things I have heard here on the panel this morning. Namely: our regulatory process has had great difficulty coping with the problems of inflation, and inflation has driven up money costs. That is the root problem that we are all discussing.

And at the same time I do want to say that from the regulatory side, we have some marvelous examples around the country of regulators working hard to represent fairly both the customer and the investor. On average we have to say that their attempts have failed, because, as a number of spokesmen, including Mr. Kennedy, have indicated, we have virtually stolen from the investor to subsidize the customers.

And this has happened nearly uniformly across the country. It is a fact of life. But the root problem playing the regulatory process is inflation. We all have said this over and over again this morning.

Mr. **Harkin**. I guess I have a hard time really understanding what you just said.

Are you saying that the regulatory process has something to do with inflation? Is that what you are saying?

Mr. **Nichols**. Inflation is the root cause of much of our regulatory breakdown. Let's imagine ourselves as regulators, and we are addressing a rate request from a utility that comes and says:

> Look, all my costs are nearly double today what they were 10 years ago, including my money costs. 10 years ago, a 12-percent return on equity was perfectly adequate, but today, with commercial paper costing over 17 percent, the prime rate being 20, today I should be allowed a 20-percent return on common equity.

The regulator has great pressure on him from all sorts of groups not to allow that significant an increase to happen. And so the pressure is on us as regulators to slow down that rate of increase in utility rates. And I understand that very well. And if we were regulators, we would understand it, because the consumer groups would be pounding on our door every single day. It's understandable that regulatory groups hate to grant the increases needed to keep utilities in reasonable shape, and it is a fact that we have had great subsidization of energy consumers over the past decades.

Mr. **Harkin**. Anyone else? Do you have any questions?

Mrs. **Schneider**. Yes.

I apologize, as I am sure my other colleagues do, for having to run back and forth so many times to vote and as a result missing information in the testimony. But you can be sure that your topic is of interest to us, and we will take advantage of the testimony already submitted.

I would like to ask Mr. Nichols a question. How many commercial and industrial audits does NEES perform per year? I realize your plan is new, but could you give me a little update as to how that's coming along?

Mr. **Nichols**. I can give you information on residential audits. On commercial and industrial, I can't. I will have to provide it for you.

Mrs. **Schneider**. That would be appreciated. I think that the whole committee would be interested in that.

[Information not available at time of printing.]

Mr. **Nichols**. I would have to say—and I am not saying it just because Mr. Kennedy is at the table. I think the large industrial customers have done an amazingly good job of conservation. They know what their costs of capital are; they know what the payoff is for investments in a new machine or new product line, or in reglazing all the windows in their buildings or putting in a new and more efficient motor to replace the one that is old, and overall they have done a fantastic job.

But I have to go back to the point Dr. Stelzer made earlier. Since the OPEC oil embargo, we have had a significant runup in energy prices, but I think we have to realize that the electric utility industry has had a faster growth than the growth of the economy since that same OPEC embargo.

We have not had a massive decoupling. What we have had is a reduction of energy use as a function of GNP growth and I believe this is largely attributable to the marvelous job that large industry has done.

Mrs. **Schneider**. You were speaking about large industry. But I certainly must admit, coming from a State which is primarily dependent on smaller industries who, at least in my State do not have the information, the access, or the capital that is necessary to make those changes. It is only now that that information is beginning to come forward.

I am playing whatever role I can to provide that information, and that is why I was curious, Mr. Nichols, about whether the businesses contract with you for audit?

Mr. **Nichols**. No; they don't contract with us. We have a number of firms in New England, both in Massachusetts and Rhode Island, particularly, that do perform commercial audits. Both Rhode Island and Massachusetts have extensive residential audit programs underway.

Mrs. **Schneider**. I am really interested in industrial firms. We are trying to keep jobs in New England. And many of these industries are coming to me and asking for information, and access to both the technological base and the financing.

Do you provide any financing?

Mr. **Nichols**. We don't provide any financing for industrial or commercial concerns. Our only financing that we do provide is we have a grants program for attic insulation for electrically heated homes. We think that is cost justified. And I wanted to emphasize, in response to the last question, that the Pacific Power & Light program is aimed at electrically heated homes. Nearly all the programs with which I am familiar—if it's a gas utility, they're aiming at gas-heated homes. If it's an electric utility, they are aiming at electrically heated homes. And this is a cost-justified program from the viewpoint of tomorrow's electric customers as well as today's electric customers. But we would be giving the wrong economic pricing signal if we raised electric rates as a way of reducing a customer's gas bill. And I think that is a point that I wanted to emphasize in response to the last question.

But believe me, it is not my experience that industrial or commercial customers are lacking in information. What we are all lacking in this case, going back to the last question—what we are all lacking is low-cost money.

Mrs. **Schneider**. Well, I think my experience, and your experience too, may be that if they know it all, they just can't afford it. But the input that I have been getting from my constituents, and others in the State and region, including the New England Congressional Caucus hearings that were held in Stamford, Conn., where many industries testified, is that they do not have access to information. And I thought the lack thereof was one of the greatest impediments, in addition to the lack of low-interest capital available to make these changes.

Mr. Chairman, do we have another vote?

Mr. **Harkin**. Yes.

Mrs. **Schneider**. Thank you.

Mr. **Harkin**. We have about 8 minutes.

Mrs. **Schneider**. Thank you.

Mr. **Kennedy**. Mr. Chairman, if you have 8 minutes and want to give it, I have a comment or two.

Mr. **Harkin**. We will allow you about 3 or 4 minutes, and that will give us time to get over there.

Mr. **Kennedy**. In response to Mrs. Schneider's inquiry as to the industrial users and audits and so forth, indeed, the large industrial firms have a great stake in the price and use of energy, and they spend money to find out how to save energy. It's a very expensive commodity. You're also right, there are many small industrial and commercial firms that do not have access to that kind of expertise.

The Los Angeles Department of Water and Power, for instance, has a consulting element that does audits and provides information. They deal primarily with air handling in commercial and small industrial establishments. They go in, take a look, and make recommendations—I believe, for no fee. They do not go into Union Carbide or General Motors plants, simply because these people are taking care of their own problems.

Mr. **Nichols**. Mr. Chairman, if I may add, we have conducted in Rhode Island a number of 2- and 3-day seminars for industrial and commercial customers just to provide that kind of information you are suggesting is needed. In fact, our Energy Institute is an outgrowth of those earlier seminars.

Mr. **Harkin**. The solution side of cheap money is what we are not doing so well.

All right. Thank you very much, gentlemen. I'm sorry again for the disruptions, but that's the way this place goes.

[Whereupon, at 11:45 a.m., the hearing was adjourned.]

APPENDIX

STATEMENT OF THE

AMERICAN PUBLIC POWER ASSOCIATION

Submitted To
HOUSE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS
"The Future of the Nation's Energy Utilities"

June 23-24, 1981

American Public Power Association is a national service organization representing some 1,750 local publicly owned electric utilities in 48 States, Puerto Rico, the Virgin Islands, Guam, and American Samoa. Public power systems serve about 33 million Americans. As non-profit consumer-owned entities, these utilities are dedicated to the need of their customers for adequate energy services at a reasonable price.

The future of electric utilities in the United States will be affected by six significant factors:

A. Availability of financing for equipment and plant required to satisfy demand for energy services.

B. Rate of growth in use of electricity for residential, commercial, and industrial purposes.

C. Role of energy conservation, load management, renewable resources, and cogeneration in supplying whatever demand exists.

D. Opportunities for new regional planning initiatives.

E. Types and price of fuels accessible to generating utilities.

F. Application of regulatory solutions which recognize differences among utility situations.

Attached to this statement are appendices which discuss each of these issues in detail.

EXHIBIT A

CAPITAL NEEDS OVER THE NEXT DECADE

The nation's local publicly owned electric utilities are budgeting $5.47 billion for new plant additions in 1981 -- an increase of 8.9 percent over the $5.03 billion they reported spending in 1980.

A year ago, in Public Power's annual survey of spending plans, the local public power systems indicated that they expected to spend about $5.29 billion. Most of the difference between 1980 projected and actual total expenditures is accounted for by the difference in 1980 projected and actual nuclear generation expenditures. This year the systems reported spending $1.91 billion on nuclear generation in 1980, instead of the $2.34 billion forecast last year. Most systems projected a decrease in 1981 nuclear expenditures; however, the total nuclear expenditures for 1981 are expected to rise 21.3 percent over this year, due to the projected increase by one system.

The Public Power spending figures are for municipal electric utilities and other local publicly owned systems and do not include federal power agencies, rural electric cooperatives or private power companies.

Spending for transmission and distribution, including substations, will rise an estimated 3.6 percent next year, as compared with a projected increase of 10.6 percent in generation. Actual expenditures in 1980 for hydro generation were less than half of what had been projected for that year, and may have been deferred until 1981, causing the 243 percent increase in 1981 projected expenditures over actual 1980 expenditures.

Public Power's survey of spending plans includes reports from hundreds of municipal and other local publicly owned electric utilities, estimated to represent about two-thirds of the total local public power segment of the electric utility industry on the basis of number of customers served. The reports have been projected to cover all local publicly owned systems.

Prices Rising. The price for building new power stations continues to rise, and the high cost of raising money has affected the municipal bond market just as it has the markets for other types of securities.

Changes in capital charges for nuclear power plants are dramatized by numbers recently released by the Tennessee Valley Authority:

The three 1,067,000 kilowatt Browns Ferry units were originally estimated at $123 per kilowatt and actually cost $284 per kilowatt when they went into commercial operation 1974 through 1977.

TVA's second nuclear facility, Sequoyah, is near completion with the receipt of a full power license for the first unit and the second unit about 90 percent complete. Cost of the two 1,148,000 kilowatt units was originally estimated at $146 per kilowatt. The current projected probable cost is $865 per kilowatt.

TVA conservatively projects major nuclear units which may come on line at the end of this decade at costs as high as $2,400 per kilowatt.

The $24 billion investment projected by the Washington Public Power Supply System for construction of five nuclear power plants with a total capacity in excess of 6,000,000 kilowatts represents more than the stock market value of the nation's four manufacturers of fission-fueled electric generating units. "We have a marketing problem," the Supply System's managing director Bob Ferguson has pointed out. "Few investors want to tie up funds in long-term issues." Like other borrowers, WPPSS must examine possibilities for such things as negotiated sales, intermediate-term financing, floating rate debt, put bonds, and warrants. In recent weeks, WPPSS has found it necessary to slow down construction of two units.

For both TVA and the Supply System, interest costs are presently a driving force in determining the price of power.

TVA Chairman Dave Freeman reported to Congress earlier this year that the agency's coal prices have jumped from $4 a ton to over $35 a ton in the past 10 years, and while fuel and power imports constitute 40¢ out of each TVA "power dollar", interest represents 30¢.

"Record volume and volatile interest rates characterized the tax-exempt bond market in 1980," the Public Power Finance Group of Lehman Brothers Kuhn Loeb reported. What about the future? The Group predicted in January:

> *"Looking ahead to 1981, volatile interest rates are expected and a larger supply of public power bonds is anticipated as several developing joint action agencies plan to enter the market for the first time in 1981, while established joint agencies look to re-enter the marketplace in financing their large capital requirements. As the competition for investment funds among public power issuers becomes more acute, these issuers will continue to explore unconventional financing techniques and will consider the use of non-traditional sources of capital, such as tax-exempt commercial paper and leasing transactions.*
>
> *"In 1981, public power issuers should encounter investors who are more demanding in their pursuit of a higher rate of return and more discriminating in their credit analysis of the respective public power issues in the marketplace. This kind of investor attitude should result in well structured power supply programs that will withstand the scrutiny of intensive credit analysis and hopefully, the test of time."*

The Group's report is attached.

Exhibit A Page 3

PUBLIC POWER FINANCING
The Year in Review
1980

January, 1981

THE TAX-EXEMPT BOND MARKET IN 1980

Record volume and volatile interest rate fluctuations characterized the tax-exempt bond market in 1980. The volume of tax-exempt bonds sold in 1980 was $46.90 billion which eclipses the old record volume of $46.21 billion set in 1978 and marks an 11% increase over last year's $42.26 billion level.*

Housing Issues Contribute to Record Volume

The rise in tax-exempt bond volume can be attributed in large part to the flood of tax-exempt housing bonds sold in 1980. A total of $14.14 billion of housing bonds, including $11.80 billion for single-family mortgage programs, reached the market during the year accounting for 30.1% of the total tax-exempt volume.

In November 1980, Congress passed new legislation concerning the controversial single-family mortgage bond financing program, which, as of January 1, 1981, drastically reduced the amount of bonds permitted to be issued for such purposes.

Bond Buyer Hits New Peak

The new tax-exempt bond volume record was set despite escalating interest rates throughout most of the year. The Bond Buyer Index (the "BBI") established all-time highs during 1980. After opening at a 7.32% level, which was close to that index's previous record of 7.38% set in October 1979, the BBI climbed to 9.44% during the last week of March and the first week of April before declining sharply to 7.11% on May 8, the year's lowest level. During the remainder of 1980, the BBI registered new highs almost every week peaking at 10.56% on December 18. This marked a 345 basis point jump from the May 8 low (See Table 1 for the five-year trend in the BBI).

Factors Causing Interest Rate Escalation

The record interest rates in the tax-exempt bond market can be attributed to a number of factors including investor expectations of continuing inflation, an expansive money supply and strong business borrowing demand which pushed the bank prime lending rate to record levels in 1980 (21½% peak).

In particular, institutional investors witnessing the volatility in the tax-exempt market were less willing to commit their funds for a thirty- or forty-year period without realizing a real rate of return over and above the inflation rate. Investors' portfolios, throughout much of 1980, suffered the debilitating effects of escalating interest rates on the values of their debt holdings (i.e. the value of fixed income securities moves inversely to changes in interest rate levels) and thus were more demanding in their quest for attractive rates of return.

This investor attitude, together with the tight monetary policies implemented by the Federal Reserve, forced interest rates to record levels and threatened the existence of the long-term bond market. These market conditions led to the exploration of a number of new financing ideas in the tax-exempt marketplace during 1980, which are discussed later in this article.

Negotiated Sales Still Increasing

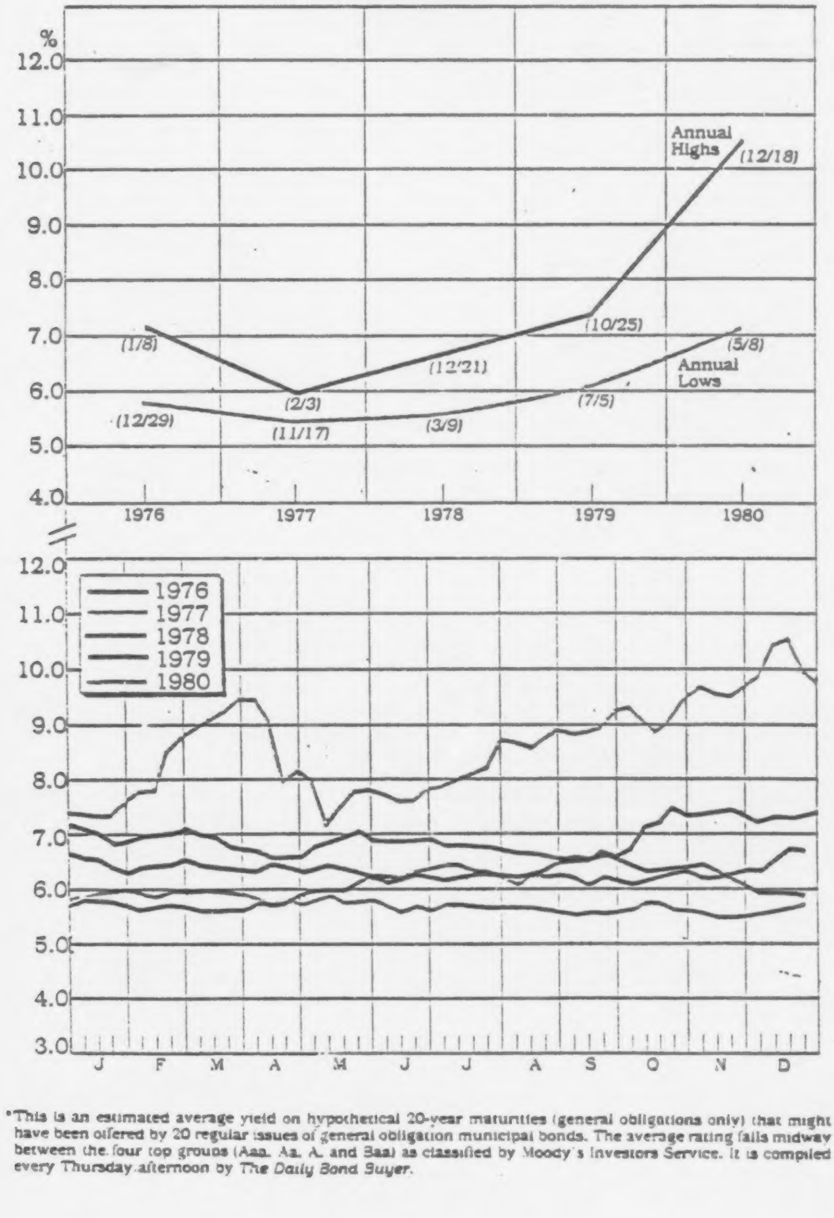
In general, the trend toward negotiated financings continued as such financings represented 58% ($27.4 billion) of all long-term tax-exempt sales in 1980, up 2% over 1979 and 16% greater than five years ago when negotiated financings accounted for 42% ($14.3 billion) of the total (See Table 2 for five-year trend).

*Tax-Exempt volume figures (total, negotiated sales and competitive sales) and housing bond volume figures (total and single-family) stated herein were compiled by *The Daily Bond Buyer*, and were revised as of January 31, 1981.

Exhibit A Page 5

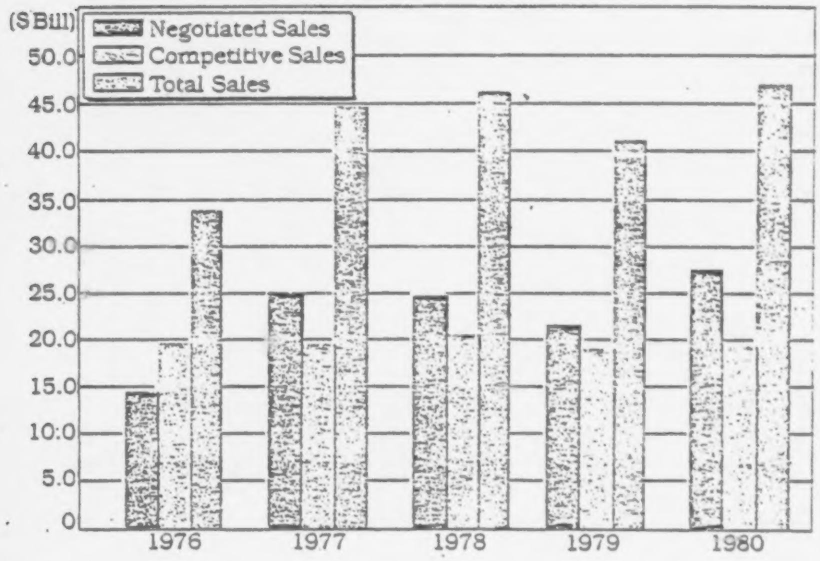
Table 1

THE BOND BUYER INDEX*
1976-1980



*This is an estimated average yield on hypothetical 20-year maturities (general obligations only) that might have been offered by 20 regular issues of general obligation municipal bonds. The average rating falls midway between the four top groups (Aaa, Aa, A, and Baa) as classified by Moody's Investors Service. It is compiled every Thursday afternoon by *The Daily Bond Buyer*.

Table 2
TREND IN TAX-EXEMPT BOND MARKET
1976-1980



PUBLIC POWER FINANCING IN 1980

In the public power sector, financings totaled $4.713 billion in 1980 which was slightly higher than the 1979 total ($4.587 billion) but far below the 1978 record of $5.786 billion of public power debt issuance. (See Table 3 for five-year trend in public power financing).

Large Issuers Continue Domination

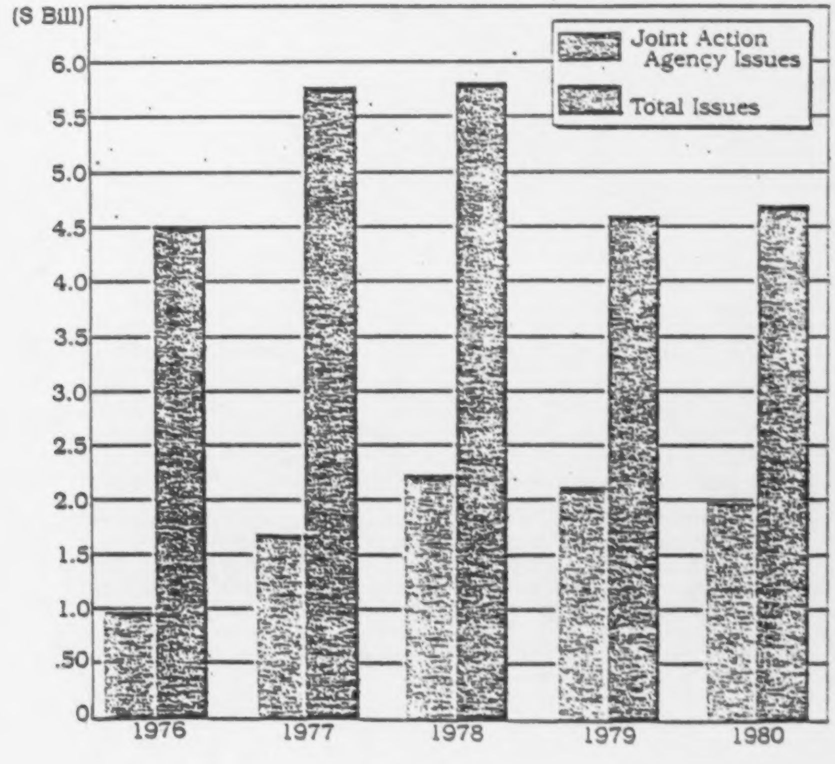
As the case has been in recent years, the public power segment of the tax-exempt market was dominated by a few large issuers in 1980. Washington Public Power Supply System ("WPPSS") alone accounted for 23.3% of the total public power financing volume, selling revenue bonds in the aggregate principal amount of $1.1 billion during the year. The top five issuers, including Power Authority of the State of New York ("PASNY") whose bond issue of $505.775 million was the largest single offering of the year, represented 50.1% ($2.361 billion) of total public power debt issued in 1980.

In addition to WPPSS and PASNY the top five issuers included Municipal Electric Authority of Georgia ($275 million), Texas Municipal Power Agency ($250 million) and Los Angeles Department of Water and Power, California ($230 million).

The balance of the top ten issuers in 1980 consisted of the Salt River Project Agricultural Improvement and Power District, Arizona ($225 million), City of Gainesville, Florida ($155 million), Orlando Utilities Commission, Florida ($155 million), San Antonio, Texas ($152.2 million), and South Carolina Public Service Authority ($125 million). Together these ten issuers represented 67.3% ($3.173 billion) of total public power financing while 85 issuers accounted for the remaining 32.7% ($1.54 billion).

Negotiated sales of public power debt continued to be predominant among large issues. While competitive public power offerings outnumbered negotiated offerings 86 to 30, the 30 negotiated issues accounted for 49.3% of the total public power dollar volume with an average issue size of $77.73 million compared to the average competitive issue size of $27.69 million.

Table 3
PUBLIC POWER FINANCING
1976-1980



Joint Action Financing Remains Significant

Joint action agencies continued to have a major presence in the public power sector of the tax-exempt debt market. In 1980, there were 14 joint action financings by seven issuers totaling $1.951 billion or 41.4% of all public power financings. In the last five years there have been 62 joint action issues by 12 different agencies aggregating $8.941 billion or 35.3% of all public power debt issues sold from 1976–1980.

The only new joint action agency to enter the bond market in 1980 was Michigan Public Power Agency, which sold its' initial offering of revenue bonds in the principal amount of $44.37 million. Platte River Authority issued $70 million of revenue bonds in 1980 after a three-year absence from the market. The remaining joint action agencies issuing bonds during the year had also sold issues in 1979 (See Table 4 for total amount of bonds sold by joint action agencies in 1980 and the last five years).

Table 4

TOTAL BONDS ISSUED BY JOINT ACTION PUBLIC POWER AGENCIES 1976-1980

Issuer	1980 Total (000)	1976-1980 Total (000)
Heartland Consumers Power District	$ —	$ 240,100
Massachusetts Municipal Wholesale Electric Company	112,000	672,870
Michigan Public Power Agency	44,370	44,370
Michigan South Central Power Agency	—	95,040
Municipal Electric Authority of Georgia	275,000	1,000,000
North Carolina Municipal Power Agency Number 1	100,000	650,000
Platte River Power Authority	70,000	297,100
City of Sikeston, Missouri*	—	240,000
Texas Municipal Power Agency	250,000	850,000
Washington Public Power Supply System	1,100,000	4,665,000
Western Minnesota Municipal Power Agency	—	164,850
Wyoming Municipal Power Agency	—	21,540
Total (all issuers)	$1,951,370	$8,940,870

*Sikeston was the lead city issuer for a number of other Missouri municipalities and a rural electric cooperative.

Alternative Financing Techniques Considered

In a year of tight credit markets, record-high interest rates, and reduced investor interest in the long-term bond market, many issuers, including public power entities, considered alternative financing techniques such as notes, tax-exempt commercial paper, floating-rate issues, "put" or bondholder optional redemption bonds and bonds bearing detachable warrants to meet their capital expenditure needs.

In 1980, more than $250 million in notes were issued by public power issuers including the Orlando Utilities Commission, Florida ($80 million), South Carolina Public Service Authority ($50 million), Lakeland, Florida ($50 million), City of Gainesville, Florida ($40 million) and Department of Water & Power of the City of Los Angeles ($40 million).

The Salt River Project Agricultural Improvement and Power District, Arizona, initiated a tax-exempt commercial paper program amounting to more than $200 million during the year.

WPPSS, in an attempt to whet investor appetites and achieve a lower borrowing cost, issued a separate series of bonds in the principal amount of $50 million maturing in 2010 with a 10-year "put" option for the bondholders. This series was issued concurrently with another series of bonds in the principal amount of $150 million structured with various maturities and traditional redemption provisions. While investors were receptive to the idea of put bonds, these put bonds were sold on a competitive basis and received a winning bid of 11¾% coupon rate (priced at par) which was 75 basis points lower than 12½% term bonds (2010) of the accompanying series of bonds and 100 basis points higher than the 10¾% coupon rate received for the 10-year serial maturity of that same series.

At year's end other issuers were considering the use of these alternative financing techniques.

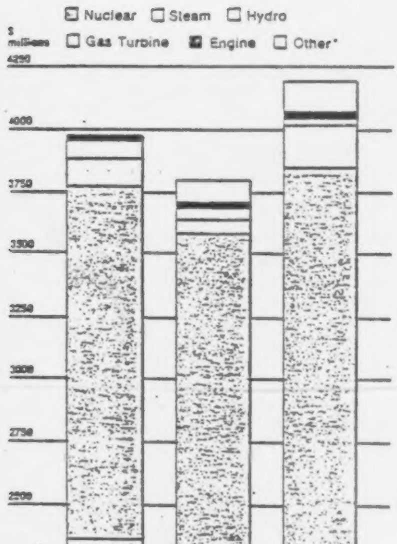
Prospects for 1981

Looking ahead to 1981, volatile interest rates are expected and a larger supply of public power bonds is anticipated as several developing joint action agencies plan to enter the market for the first time in 1981, while established joint agencies look to re-enter the marketplace in financing their large capital requirements. As the competition for investment funds among public power issuers becomes more acute, these issuers will continue to explore unconventional financing techniques and will consider the use of non-traditional sources of capital, such as tax-exempt commercial paper and leasing transactions.

In 1981, public power issuers should encounter investors who are more demanding in their pursuit of a higher rate of return and more discriminating in their credit analysis of the respective public power issues in the marketplace. This kind of investor attitude should result in well structured power supply programs that will withstand the scrutiny of intensive credit analysis and hopefully, the test of time.

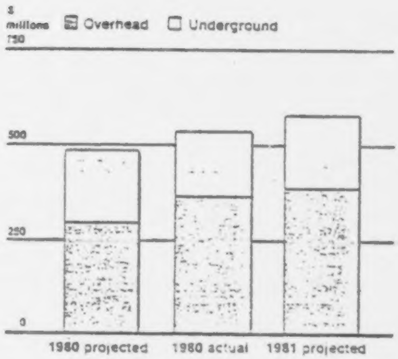
Exhibit A Page 10

Local Public System Plant Additions and Improvements

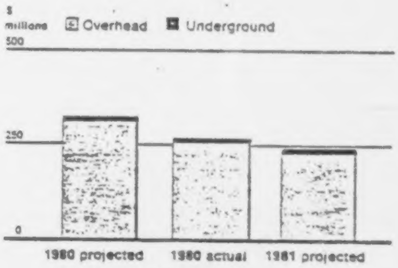


Generation

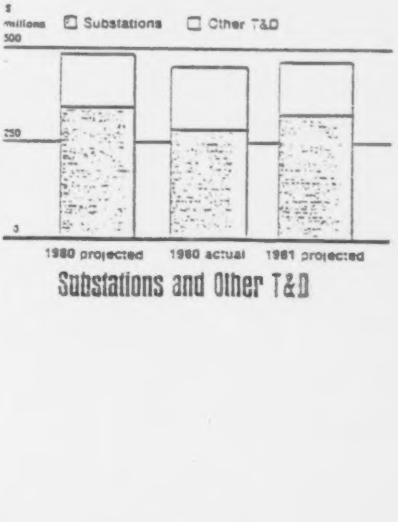
* "Other" generation includes geothermal, solar, wind.



Distribution below 33kv



Transmission above 33kv



Substations and Other T&D

EXHIBIT 8

DEMAND FORECASTS

One of the areas of greatest utility uncertainty is the planning of future load growth. Although there are highly sophisticated econometric techniques for load forecasting, in the final analysis most of these rest upon assumptions that are gleaned from best estimates or judgment calls.

Because the United States does not have a fully integrated national electric power system, and there are important regional differences both with regard to supply and demand, it is difficult to discuss load growth from a national perspective. Some public power systems in towns with diminishing population may be experiencing negative load growth while other communities with a growing industrial base are dealing with load growth above the national average. Nevertheless, national trends might provide guideposts to your planning for the future.

Electric utilities for the past few years have been revising their load estimates downward. No one can speak with certainty as to future demand, because no one can predict the state of the Nation's economy, the impact of international events, changes in lifestyles, the extent of conservation's effect on demand, or a host of other factors that could influence future demand for electricity.

Yet, there are a number of factors which would indicate the need for new generating capacity. These include new housing that will be required for an increased population and new famililties that are being formed because of the post-World War II baby boom; the need to replace existing oil-fired generating capacity becuase of national security considerations; switching of consumers to electricity because of the shortage and price of alternative energy sources, and the fact that electricity can be produced from a variety of sources; the increased need for energy for upwardly mobile sectors of society; the development of new energy-consuming products that cannot be foreseen at this time; the possible switching of elements of our transportation system from liquid fuel to electricity; and the need for new sources of energy for continued economic development.

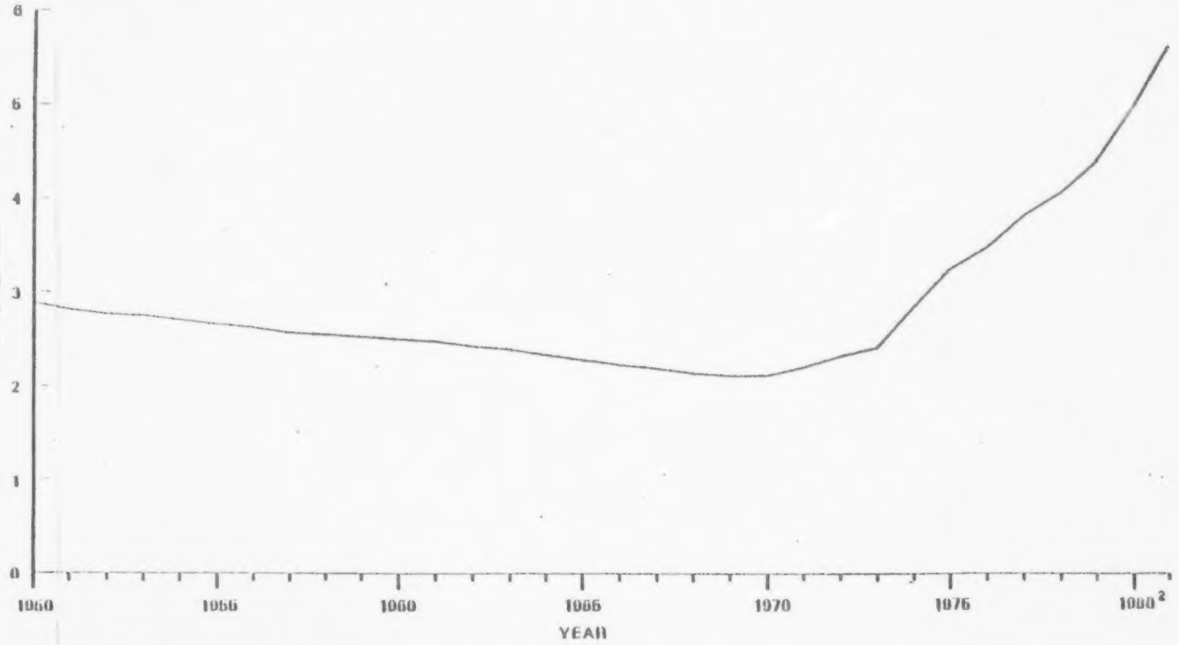
Despite these pressures for increased demands for electric capacity, the slowdown in load growth during the past few years has resulted in a downward revision of load growth. The most recent forecast for this decade by the National Electric Reliability Council predicted a 4 percent annual growth in peak demand for utilities during the period 1980-1989, while the Department of Energy predicted an annual growth rate of 2.1 percent.

The 4 percent annual growth projected by NERC is significantly lower, of course, than the traditional 7 percent experienced by utilities for many years, but we should by no means minimize the magnitude of construction that would be required even at this slower growth rate. Assuming a 4 percent annual increase, the peak demand in 1989 would reach, according to NERC, 607,974 megawatts, or 182,437 megawatts above the level of 425,537 expected to be reached in 1980. In order to meet this expected increase in demand, U.S. utilities are now planning to add 212,530 megawatts to installed generating capability between the winter of 1980-81 and the winter of 1989-90. This increase in a 10-year period can perhaps be viewed in better perspective when we keep in mind that in 1945, at the conclusion of World War II, the Nation's entire electric generating capacity, built up over more than half a century, was only 50,111 megawatts. Thus, we have no small job facing us in the decade ahead. Keeping up with power demands, while at the same time coping with many new, unprecedented problems will be a Herculean task.

Clearly the price of power plays a part in determining load growth. Reduction in use and employment of more efficient machines and methods in homes, stores, and industries will affect future load growth. The attached chart shows what has been happening with respect to residential electric rates.

U.S. AVERAGE ELECTRIC RATES [1]

CENTS PER kWh
Residential[1]



1. Source: Tennessee Valley Authority
2. Twelve months ending September 1980

EXHIBIT C

ROLE OF CONSERVATION, LOAD MANAGEMENT, RENEWABLES AND COGENERATION

Within the past year, a new phrase -- "energy services planning" -- has entered the lexicon of many persons associated with publicly owned electric utilities. It is a concept we are destined to hear about in more detail in the years ahead.

What is energy services planning? It is a concept derived from the premise that the consumer is interested in certain services provided by energy -- that is, heating, cooling, lighting, operation of various appliances -- rather than obtaining electricity, per se. Consequently, the objective of the utility should be to provide these energy services in the most economical or "cost-effective" means possible. Basically, the energy services concept has four elements:

1. Emphasis on provision of consumer services (as opposed to simply selling electricity or some other form of energy).

2. A goal of meeting demand for a given level of service in the most cost-effective manner (including the possibility that the result will be a reduction in use of electric capacity and energy).

3. Planning based on a variety of alternatives stretching from end-use controls through consumer-utility cooperative energy endeavors to conventional power plant construction (with the objective of determining the least-cost answer for any given planning period).

4. Utility investment or assistance in putting in place energy facilities which save consumers money (even though such aid may be outside traditional generation, transmission and distribution projects and may involve consumption rather than supply).

Events in the past few years -- particularly the sharp rise in the price of energy -- have provided the impetus for energy services planning. The attached graph shows how electric rates have sloped upward. However, the impact is not necessarily geographically even. Electric rates vary considerably from place to place, as indicated in a survey of 130 utilities serving 70 percent of all residential customers carried out by Midwest Research Institute. For actual amounts of electricity consumed, the overall rates ranged from 1.48¢ to 11.8¢ -- a difference of 800 percent and probably more than any other widely used commodity.

How does the "energy services planning" concept relate to local public power systems?

Municipalities which operate their own electric utility are both a provider of services and a consumer of these same services. Hence, the benefits of integrated operation aid the community in two ways -- through lower charges for city functions (pumping water, disposing of waste, lighting streets) and through minimizing rate increases for power used to illuminate, heat, cool and run homes, businesses and industries.

Energy problems loom with ever greater importance to all American communities. A recently released survey by the National League of Cities showed that 1,564 city officials asked to evaluate the relative seriousness of 35 specific problem areas within their community ranked the cost of energy the highest with over 86 percent of respondents identifying it as either a "moderately serious" or "very serious" difficulty. A shortage of energy ranked ninth on the list of serious problems with over 56 percent of city officials identifying it as "moderately serious" or "very serious".

Municipal electric utilities are especially receptive to dealing with this problem because they are non-profit organizations, devoted solely to the service of the community, and interested in increasing the quality of that service while holding down its cost.

About 90 percent of these systems have 10,000 customers or less, and thus have a close contact with many individual consumers.

City-owned systems are in the main self-regulated and autonomous in their decision-making; after opportunity for citizen input, a city council or utilities board can determine the proper course for the community, and the governing group has a capacity to implement the choice.

Availability of municipal bonds and retained earnings gives these systems a self-executing financing capability.

The multiple-function responsibilities of cities lead them naturally to examination of chances to blend services economically, e.g. off-electric peak pumping for sewage disposal, introduction of a turbine-generator in connection with the local water supply reservoir, down-town heating and/or power production by incinerating garbage, cogeneration from a city hospital, use of waste heat from generating facilities to distill alcohol to fuel city vehicles, tapping of methane gas at sanitary landfills and sewage disposal plants to burn under boilers or in engine generating sets, etc.

The new economics of electric power are eroding the distinction between utility and customer. Consumers are not only weatherizing, insulating, and thermostating their homes and offices, they are encouraged by public policy to own and operate active electric production sources, e.g. power producing windmills and small scale hydroelectric plants, a function usually performed by utilities. In addition, utilities are successfully inserting in houses and other buildings remote controlled load management devices which, in effect, allow the utility to use the customers' equipment as pseudo-peaking plant. Utilities are making or contemplating investment in features of individual homes -- attic fiberglass or thermal storage heaters -- with retention of utility ownership and payment of monthly fees by consumers.

A major return to co-generation and small scale hydro in the U.S. could further intensify the trend toward merger of user-producer, with utilities buying all of the output of a non-utility generating facility and selling that entity electricity to satisfy its demand. This movement, if cost-effective for consumers, moves the concept of integrated energy systems an evolutionary step further in direct involvement of the utility with its customers. It is stimulated by existing tax credits and Federal requirements that utilities purchase at "avoided cost" the output of non-utility co-generators and small power producers.

Expansion of use of total energy systems which employ diesel engines or fuel cells to produce electricity and capture by-product waste heat for warming water or space, or development of economic photovoltaic arrays positioned on individual roofs, might push utilities in the direction of installing, servicing and/or operating energy production equipment as opposed to operating central station power production plants.

There are definite economic, electrical, and even aesthetic advantages to a public power system and the community it serves in integrating the interest of the individual and the total local populace in these new energy applications. If that were not true, requirements of Federal law dictate it for certain systems.

New Approaches. During the same decade that the cost of conventional electric generating equipment was steadily rising, the cost of semi-conductor silicon chips on which much energy management equipment is based was steadily falling.

Today energy management systems -- microprocessors or minicomputers which control energy-consumer equipment in buildings -- are being put into service at the rate of 12,000 to 15,000 new systems per year for an annual installed value of $450,000,000 to $550,000,000, according to Booz, Allen and Hamilton. The firm found that systems paid for themselves in three years or less.

Municipal electric utilities have also discovered the quick payoff of load management equipment. An example is the Albany, Georgia, Water, Gas & Light Commission which has almost 5,000 central air conditioners and water heaters under load management control. It has been determined that the entire load management network paid for itself in only 60 minutes of use the summer of 1978 when it was instrumental in reducing Albany's peak demand by 9,500 kilowatts to 139,000 kilowatts, equivalent to a savings of more than $540,000.

Energy conservation is now viewed as a "resource" in the Pacific Northwest as a matter of law and common sense, according to public power leaders there.

The Bonneville Power Administration, the Federal marketing agency which is the region's major power supplier, last week announced a six-point, $400 million, five-year program that will "acquire" 300,000 average kilowatts of electricity for the region at the "bargain basement" price of 2¢ per kilowatt-hour.

"That is enough to serve a city the size of Spokane at a cost less than half the four-to-six cents per kilowatt-hour we are presently paying for new thermal resources," a BPA spokesman said.

Within the past few weeks, a 59 percent majority of voters in Burlington, Vermont, approved a $2,000,000 electric department bond issue to finance a conservation and load management program. The Burlington Electric Department will begin studies immediately to determine what kind of load management system would best suit the utility. Under the conservation program, the electric department will, upon request, go into homes to make conservation improvements including (a) turning down temperatures on hot water tanks, (b) installing insulation jackets on water heaters, (c) attaching flow controllers on sink faucets and showerheads, and (d) installing gaskets on electric outlets to help reduce space heating costs. (Burlington is already embarked on a program to burn wood chips in a 50,000 kilowatt generating unit, 30 percent of the output of which will go to a joint action agency, the Vermont Public Power Authority.)

The new economics of power supply is causing a revival of interest in decentralized power production in smaller units.

One example of support for such dispersed generation is the number of filings at the Federal Energy Regulatory Commission for permission to build generating facilities at dams, particularly small scale hydroelectric installations. At the beginning of the year, a total of 1,200 applications were pending at FERC, and most were for low-head sites. Under existing law, local public power systems have a preference in permitting and licensing for all such projects over 5,000 kilowatts in size. Hydro projects are economically appealing today because construction costs may be minimized by use of existing dams, leadtime is relatively short, falling water is a renewable resource and a non-polluting inflation-free "fuel", useful life may stretch to 100 years, and operation and maintenance is de minimus.

Innovative Approaches Implemented. In an effort to improve the quality and range of energy services, public power utility systems have initiated a number of innovative projects. The uncertainties of cost projectsions, leadtimes, fuel availability, load growth, and government regulations associated with many of the conventional electricity generation options have led public power systems to explore opportunities in unconventional technologies. Through the pursuit -- wherever possible -- of an integrated energy systems approach, overall costs to the consumer may be minimized while prospects for local energy security are maximized. Here are some examples of such approaches:

- Five municipalities are participating in demonstrations of Rankine cycle "bottoming" systems that promise to boost generation output by about 10 percent without using any additional fuel. Easton, Maryland, Homestead, Florida, Beloit, Kansas, Rockford, Illinois, and Rockville Centre, New York are working with the Department of Energy and the Sundstrand, Mechanical Technology, Inc. (MTI), and Thermo Electric Corporation in implementing this technology.

- An engine operating on unconventional gas has been prominent in an eight-year program for landfill-gas recovery, recently turned commercial, by the Department of Water and Power in Los Angeles, California. The gas recovery facility will provide enough fuel to the Valley Generating Station to annually displace the consumption of 83,000 barrels of oil, generate 28 million kwh of electricity -- enough for about 8,000 residential customers -- and control gas migration at the landfill.

- The Electric Department of the City of North Little Rock, Arkansas has under study the installation of a 30 megawatt combustion turbine to be fueled in whole (or in part) by used crank case lubricating oil and scavenged diesel fuel available from the local MO-PAC railroad system service and maintenance center.

- Palo Alto, California has proposed a four-part solar energy program aimed at installing 3,000 solar heating systems in the city over the next five years. The program consists of an information center, a municipal solar utility program to facilitate the adoption of solar systems through financial assistance, a "Solar Pal" award program to provide cash incentives for solar projects, and a legislative program to facilitate solar utilization and implementation.

- Turlock Irrigation District (TID), Turlock, California, is harnessing the energy in its main canal by directing the irrigation water past two 500 kw turbine generators on its way to the farms of central California. The power produced by the new Hickman Powerhouse is enough to serve approximately 1,000 homes, saving the equivalent of 8,000 barrels of oil a year in the process. Moreover, this electricity is available when it is needed most -- in the hot summer months when the utility experiences its peak demand. TID is also evaluating advanced concepts in run-of-the-river hydroelectric technology.

- Burlington, Vermont, has been using wood chips from forest residue since 1977 to fire its 10 mw J. Edward Moran Generation Station. The City has plans for a 50 mw wood-fired facility.

- Eugene, Oregon, is collaborating with the Weyerhaeuser Company in the generation of 51.2 mw of electricity from steam supplied by boilers fueled with a by-product of the pulp and paper process.

- Lamar, Colorado, has constructed a large-scale bioconversion facility which will produce methane gas from the manure of roughly 50,000 feedlot cattle. It is estimated that through anaerobic digestion about one million cubic feet of gas will be produced every day.

- Ames, Iowa, has burned municipal solid waste in a modified three-unit 60 mw steam plant since 1975.

- Columbus, Ohio, has broken ground for its 90 mw trash-fired power plant which is expected to consume about 3,000 tons per day of municipal solid waste.

- Taunton, Massachusetts, is studying an integrated municipal energy resource system. This concept will be evaluated in the light of (1) over-reliance on oil for power generation, (2) inadequate land for municipal solid waste disposal, (3) inefficient utilization of energy resources, and (4) handling and disposing of sewage sludge. These problem areas will be addressed through a consolidated municipal approach in identifying the state-of-the-art in the combustion of coal, refuse, and sludge; district heating and cooling; resource recovery; and sludge processing and drying.

- Massachusetts Municipal Wholesale Electric Company, Ludlow, Massachusetts, will be recovering heat rejected from its 346 mw combined-cycle power plant to provide space conditioning for its headquarters office building in Ludlow. The power plant will be operating on an intermediate cycle, roughly 70 hours per week, to service the building on a round-the-clock basis. This heating system will utilize a 10 million gallon water storage tank which provides makeup to the various cooling systems within the plant.

- Easton, Maryland, is helping its consumers meet their heating and cooling needs by providing water-to-air heat pumps which use city water as a heat source/heat sink. The water distribution system for the town maintains an average summer temperature of about 60° F. and about 50° F. in the winter, significantly different from ambient conditions. Recently the Easton Utilities Commission acquired a mini-computer to facilitate detailed calculations on the performance and potential impact of this novel district heating program.

- Philippi, West Virginia, will determine and document consumer attitudes on electricity and energy conservation as the initial step for a city-wide residential load management program. This will provide a guideline for other communities that are examining the institutional and technical questions relating to load management.

- Albany, Georgia, has almost 5,000 central air conditioners and water heaters under load management control. The load management system is a hybrid of radio and power-line carrier communication equipment which is directed by a supervisory control and data acquisition system to provide optimum speed and accuracy. It has been determined that the entire load management network paid for itself in only 60 minutes of use in the summer of 1978 when it was instrumental in reducing Albany's peak demand by 9.5 mw to 139 mw, equivalent to a savings of more than $540,000.

Industrial cogenerators once produced about 30 percent of the nation's electricity. Since then, the proportion has fallen to 5 percent, driven down by the availability of lower-cost utility service. But today's energy economics suggest a comeback for cogeneration. At major steam power plants, for every unit of heat which generates electricity, two units are wasted to the air or water when they might be used for manufacturing processes or space heating. Cogeneration could put more of that heat to work. Public power systems in some parts of the country have already concluded mutually beneficial arrangements with industry partners, and more can be expected.

Co-generation Examples. Throughout the country, public power systems have recognized the potential for cogeneration and are taking an aggressive role in its promotion. Many public power systems have a long history of cogeneration. Cogeneration is not a new technology. The economics may have turned against it for a while, but cogeneration never disappeared.

Among the first public power cogenerators were some 29 municipalities in Minnesota which provided steam to residential, commercial, and industrial customers from extraction turbines and diesel engines. Detroit Lakes was the first with a low-pressure district heating system in 1902; Virginia, Minnesota introduced high pressure process steam in 1919. Fourteen of these 29 systems have been abandoned since 1965, however. This is primarily due to declining system performance (steam distribution efficiencies approaching 50 percent), the high cost of rehabilitation, declining sales, and low load factors for the district heating systems.

The Public Utility District in Cowlitz County, Washington, has for the past fifty years engaged in cogeneration with local forest-products industries. The utility "wheels" the output from the combined 145 mw facility owned by the Longview Fiber and Weyerhaeuser corporations to the Bonneville Power Administration, which credits the industry for the power. Similar cogeneration efforts in Washington

State are underway in Grays Harbor County, Camas, Everett, Cosmopolis, Shelton, Omak, Snoqualmie Falls, Moses Lake, and Toppenish. The specifics of these and other cogeneration systems in the Pacific Northwest can be found in the report, "Industrial Electrical Cogeneration Potential in the Bonneville Power Administration Service Area," by the Rocket Research Corporation (January 19, 1979). It has been determined that this region represents a technical potential for 1,430 mw of cogeneration, 82 percent of which is in forest-related industries.

Public power is engaged in new cogeneration projects as well -- some of which renew a commitment to cogeneration district heating. For example, the Department of Public Utilities in Tacoma, Washington, along with the Rocket Research Corporation has undertaken a study cosponsored by APPA to assess the feasibility of firing their Steam Plant No. 2 with wood waste and refuse-derived fuel (RDF).

Steam Plant No. 2 was constructed in 1931. It has been idle since 1973. The boilers were originally designed to burn pulverized coal.

Preliminary analyses of cogeneration options indicate that retrofitting Steam Plant No. 2 offers significant economic advantages over building a new facility. Specifically, it appears that the most cost-effective approach would be to utilize burners -- possible fluidized bed or suspension -- external to the boiler and convey the hot combustion gases through ceramic-lined ductwork into the existing boilers for steam generation. This determination is based on the comparatively slow burning rate of wood or RDF which, if used directly, would require extensive modification of the existing fuel system. The quantity of electric power generated by the Tacoma cogeneration system will be dependent on the steam demand. If not used locally, the electricity would be wheeled to the BPA or other entities.

Estimates are that the busbar cost of the electricity will be roughly 9 mills/kWh, which compares favorably with 30-40 mills/kWh projections for the output from new power plants in the region.

Steam will be used for any of a dozen possible industrial, commercial, or residential applications in the Tide Flats area of Tacoma. The steam distribution network will consist of steel pipes with fiberglass insulation. The lines will be installed underground in steel culverts with expanion loops or bellows to handle thermal expansion, where necessary.

Current prices for the wood waste and RDF fuels range from $0.20 to $1.50/million Btu, one-third to less than one-tenth the cost of a thermally equivalent amount of fossil fuel. The Army has expressed interest in a cooperative arrangement with the Tacoma utility whereby the Fort Lewis base would supply waste wood and solid wastes in exchange for steam and electricity. Similar discussions are underway between the Army and Seattle, Washington; Fayetteville, North Carolina; La Grange, Georgia; and the Municipal Electric Authority of Georgia.

Nashville, Tennessee is considering an enterprise that, in many ways, is similar to Tacoma's. The Nashville Electric Power Board's proposed $70 million

Solid Waste Energy Recovery Facility would incinerate 1,450 tons of refuse daily to generate electricity and process steam, and possibly produce chilled water for air conditioning. The generating unit will be either one 40 mw or two 20 mw back-pressured extraction turbines.

The facility will be sited in proximity to the process steam load in order to maximize thermal transfer efficiencies. It is anticipated that the electric power will be sold directly to the Tennessee Valley Authority. On August 30, 1979, the TVA established its support of cogeneration in the following policy statement:

> *"Cogeneration results in improved efficiency of fuel use by either sharing heat or steam from a power plant or by generating electricity from waste fuels or waste heat derived from industrial processes. In addition to the improved efficiency of fuel use sources that would result from greater use of cogeneration, increased cogeneration would also help TVA defer the installation of expensive new capacity, thereby keeping rates lower than would otherwise be required. To encourage greater use of cogeneration in the region served by TVA, thereby benefitting the TVA power system and ultimately the consumers of TVA power, the TVA Board wishes to establish an experimental program:*
>
> 1. *To provide a market for electrical energy produced by cogenerators in the TVA region. TVA is prepared to enter into arrangements for as long as 10 years for the purchase of such energy.*
>
> 2. *To provide attractive standby power charges for cogenerators.*
>
> 3. *To provide technical assistance to potential cogenerators."*

Efforts comparable to those underway in Nashville and Tacoma are planned or ongoing at: Columbus, Ohio; San Antonio, Texas; Richmond, Indiana; Houlton, Maine; Braintree, Massachusetts and the Massachusetts Municipal Wholesale Electric Company; Los Angeles and Alameda, California; Springfield, Missouri; Lakeland and Jacksonville, Florida; and Memphis, Tennessee.

For those who think of cogeneration only in terms of industrial and urban application, it is significant to highlight the work that is being done in Kansas to use cogeneration in a rural setting. With the help of the Kansas Energy Office and the Ozark Regional Commission the municipal electric utility of Burlingame is building a grain drier using exhaust heat from the internal combustion engines of the municipal power plant.

In a recent article in Public Power magazine Randall Noon and Thomas Hochstatler point to the widespread opportunities to cogenerate from municipal power plants in rural areas. Many of these power plants are internal combustion engines with only a 33 percent rate of thermal efficiency. In those instances where municipal power plants are located close to varied agricultural activities, agricultural processes requiring low to medium grade heat are a logical match for municipal power plant cogeneration. Natural gas now used by the agricultural sector could be replaced by this cogenerated heat. Mr. Noon and Mr. Hochstatler highlight three main opportunities for cogeneration in rural areas -- ethanol production, grain drying and wood drying.

The City of Santa Clara, California, has been very active in the area of cogeneration. In December, 1980, Santa Clara began operation of a 5.8 mw cogeneration plant. Owned and operated by the city, the plant generates electricity for the City's electric department and provides steam to California Paperboard Corporation for manufacturing processes. The cogeneration project consists of two gas-driven turbine generators which supply electricity to about 8,000 residences. The plant is the first electric generation Santa Clara has had in about 75 years. Gases produced in the turbines pass through a duct to a boiler where the heat boils water and generates 38,000 pounds of steam per hour for use by the paper company. Steam produced through the cogeneration process costs about 8 percent to 10 percent less than if the company generated its own steam. The City is planning two more cogeneration plants as a means of insuring low cost electric resources for the future.

One of the most interesting cogeneration activities that Santa Clara has been engaged in is a feasibility study of integrating a 4.8 mw fuel cell with the industrial process of a local paper mill. The fuel cell is an electrochemical device that converts chemical energy directly to dc power. Hydrogen and oxygen are combined in the presence of catalysts to produce hot water and dc current. The fuel cell offers a number of advantages over conventional thermal generators.

1. The fuel cell's efficiency is not limited by the same thermodynamic constraints as a conventional steam plant.

2. The system is small and modular which minimizes lead time and siting difficulties.

3. The fuel cell is environmentally attractive. It is quiet, has low emissions and limited water demand. In fact, there are dry cooling options.

Without derating its capacity the fuel cell produces as a byproduct of its operations two categories of waste heat -- low temperature steam and high temperature water.

The Santa Clara study concluded that the total energy efficiency of energy production for the fuel cell which they conceptualized, would be 84.4 percent operating on naphtha and 81.4 percent operating on natural gas.

The study concluded that waste steam could be used in the paper mill's medium pressure dryer section, which consists of heated drain type rollers over which wet paper stock is passed, while the hot water from the fuel cell could be used for pre-heating air in the mill's vapor absorption system. Hot air is used in the plant to reduce relative humidity and prevent condensation by the dryers.

These two uses of waste heat were estimated to reduce the steam demand on the paper mill's boilers by 16,600 pounds per hour. That would in turn cut boiler fuel consumption by 22 percent. The energy saved is equivalent to 37,000 barrels of oil per year.

At APPA we are extremely enthusiastic about the fuel cell. We call it the "dream machine" since it offers the prospect of an energy efficient reasonable cost source of local power generation for public power systems. Better yet natural gas, an extremely compatible fuel and one which is relatively inexpensive, appears to be in greater supply than we imagined.

The Reagan Administration seems to share our enthusiasm for the fuel cell. In the midst of the deepest budget cutting that Washington has ever seen, the Administration has recommended that funding for fuel cell research be left intact. In a statement on behalf of the Reagan Administration before the House Committee on Science and Technology Subcommittee on Energy Development and Applications Roger Legassie, Acting Assistant Secretary for Fossil Energy of the Department of Energy, made it clear that cogeneration prospects for the fuel cell is an important factor in that recommendation. Mr. Legassie stated that "the high efficiency of fuel cell power plants at full or modular scales, the negligible environmental intrusion, and the ability to operate using a wide range of hydrocarbons make fuel cells attractive for a variety of applications. If economic targets can be met, fuel cells could find significant use in electric utility applications, industrial cogeneration, and for on site total energy systems where the utilization efficiency can exceed 80 percent."

To recognize innovative thinking on how to solve electric service problems, the American Public Power Association recently initiated the Energy Innovator Award. The attached article describes the program.

APPA launches DEED

by ERIC LEBER *a contributing editor of PUBLIC POWER and APPA director of energy research as well as the Association's staff liaison for DEED*

TO INCREASE THE ENERGY OPTIONS available to publicly owned utilities and their consumers, APPA has introduced DEED (Demonstration of Energy-Efficient Developments). This program will help members identify and obtain information on new energy technologies and techniques for field testing and evaluation.

DEED represents public power's commitment to and demonstration of energy efficiency. It is a program in which all publicly owned electric utilities can take part. Its symbol is the Greek letter "eta," used to symbolize efficiency.

With today's uncertainties in fuels, economics, power plant performance, demand growth, regulations and environmental impact—combined with a greater responsibility for consumer services—a nuts-and-bolts program such as DEED is particularly needed. It represents the "tire kicking" phase for new products and processes. Broad dissemination of the results of these projects will acquaint DEED participants with the characteristics of new approaches to providing energy services. DEED will emphasize information exchange.

APPA President Earl Brush put it this way in writing to Association members on behalf of DEED:

> "Improvements in the way we do business are essential to deal with an energy economy plagued by scarcity and inflation. We owe it to our consumers to do as much as we can to bring on new developments which will get more work out of the same input of energy, use resources which are not depleted in the process of producing energy, reduce adverse environmental consequences of energy production, and allow a decrease in our overall energy requirement. Our goal will never be reached if everyone stands around and waits for the next person to put up the necessary money."

Philosophically, DEED is closely related to APPA's current research program. (See listing of research projects below.) Both efforts are geared to promoting technologies that enhance the efficiency, productivity, and economic viability of publicly owned utilities. The main difference is DEED's focus on near-term applications.

DEED relates to the Electric Power Research Institute (EPRI) and other research establishments in about the same way. Its goal is to promote the transfer of R&D products out of the laboratory and into the field.

Technologies Considered

Broadly speaking, the types of technologies that will be considered include:

- new opportunities relating to transmission and distribution;
- energy storage technologies;
- load management options;
- heat pumps;
- alternative fuels (including municipal solid waste and agricultural byproducts;
- distributed fuel cells;
- residential technologies;
- wind and direct solar systems;
- screening methodologies and improvements in small-scale hydro;
- diesel engine retrofit;
- potential for fluidized-bed combustion;
- heat recovery (including heating and cogeneration);
- high-efficiency electric motors;
- electric and hybrid vehicles; and
- environmental control technologies.

The scope of this effort will broaden as new developments become available.

DEED also strives to encourage the creative approaches to improved energy services that many of the consumer-owned utilites have already initiated. Almost 300 innovative projects, conceived and executed by public power systems, were recently highlighted in PUBLIC POWER. ("Public Power Innovation," May-June 1980, p. 16. Reprints of this 16-page illustrated article are available from APPA.)

Here's how DEED will work:

- Public power systems are asked to contribute to the program. Contributions are low—just 10 cents yearly per customer, with the option of 1 cent per customer for members of EPRI.
- Proceeds go into the DEED fund administred by APPA with assistance of a DEED advisory committee composed of representatives of APPA member systems.
- Money will be used to finance demonstration of projects which will help small, medium and large public power systems use new technologies and devices to increase efficient use of energy.
- Each DEED participant will receive an eight-page quarterly report describing actual demonstration results; providing names, addresses, and phone numbers of people with facts about developments of interest to you; and answering questions raised by local public power systems.
- Periodic special reports with detailed

information on demonstrations will be sent to participants.

- Each participant will receive each year a DEED certificate (suitable for wall mounting) indicating that it is an annual supporter of the program.
- A special DEED charter membership certificate will recognize members contributing in 1980.
- An honor roll of DEED supporters will be published in APPA's PUBLIC POWER WEEKLY newsletter.

ENERGY INNOVATION JUDGES

Carey

Dreyfus

Freeman

Hayes

King

Latimer

Massey

McCloskey

Sant

Seaborg

Tape

Wilson

Award For Innovation

Besides providing material, technical and moral support for appropriate new energy endeavors, DEED recognizes outstanding innovative efforts with the Energy Innovator Award (shown on the cover). One or more awards will be given annually to systems that have been exceptional in rendering an array of energy-related services. The judges will be:

Gerald Tape, president, Associated Universities, Inc.;

Glenn Seaborg, associate director., Lawrence Berkeley Laboratories, University of California;

S. David Freeman, chairman of the board, Tennessee Valley Authority;

Michael McCloskey, executive director, Sierra Club;

Roger Sant, director, Energy Productivity Center, Carnegie-Mellon Institute of Research;

Daniel A. Dreyfus, staff director, Senate Energy and Natural Resources Committee;

Denis Hayes, director, Solar Energy Research Institute;

Llewellyn King, editor and publisher, THE ENERGY DAILY;

George Latimer, mayor, St. Paul, Minn.;

Walter Massey, director, Argonne National Laboratory;

Margaret B. Wilson of Wilson, Smith & Smith, and chairwoman of the board of the National Association for the Advancement of Colored People (NAACP); and

William D. Carey, executive officer, American Association for the Advancement of Science.

In summary, DEED's goal is to build a strong technology base supporting the fundamental objectives of locally owned public power: a healthy economy and a clean environment for the community, public participation in planning the energy future, and a degree of local energy independence.

At this writing— only four weeks after the introduction of DEED—35 public power systems have already signed up. This indicates a degree of enthusiasm that is most welcome.

Do Your Good Deed Now

If you have not received a DEED participation form, write APPA to get one. If you have a form, APPA urges you to fill it out and mail it to the Association. As APPA President Brush said in September in writing all APPA members:

"Your involvement will be a 'deed' of which you can be proud." →

APPA-FUNDED RESEARCH PROJECTS

THE APPA RESEARCH PROGRAM, parent of DEED, has provided $671,930 to 30 projects during its six years of existence. Grants ranged in size from $10,000 to $156,000. By fiscal year the grants amounted to:

975—$73,000 1978—$ 68,980
976— 32,500 1979—236,000
977— 49,350 1980—212,100

The individual grants assisted the following projects:

1975

- Study of the environmental effects of burning solid waste as a fuel—Ames, owa received $20,000.
- Installation and assessment of solar heating and cooling systems in a community center—Santa Clara, Cal. received $5,000.
- Design and assembly of a mobile cable testing laboratory for testing extruded dielectric cables rated 15 kv through 35 kv—General Cable Corp. received $48,000.

976

- Construction and evaluation of home with solar-assisted heat pump for space conditioning—Lincoln, Neb. received 12,500.
- Development of initial phase of city-wide industrial load management and control system—Burbank, Cal. received $20,000.

977

- Study of the effects of burning solid waste on boiler corrosion—Ames, Iowa received $10,000.
- Preliminary evaluation of the environmental, economic and social impacts of a regional 300-mw synthetic fuel combined cycle plant—Columbia, Mo. received $15,000.
- University of Nebraska study of the economics for producing chemicals and fertilizer from the by-products of coal processing—Loup River Public Power District, Neb. received $14,350.
- Examination of the role of dispersed generation in municipal utilities by Burns and McDonnell Engineering Co.—cosponsored with the Electric Power Research Institute which received $10,000.

978

- Development of a load forecasting computer model for commercial and industrial customers—Salt River Project in Phoenix, Ariz. received $20,000.
- Establishing a test method for estimating the life expectancy of underground distribution cables—Cable Technology Laboratories, Inc. received $29,000.
- Assessing the potential of retrofitting heat pumps as an energy conservation measure—Palo Alto, Cal. received $19,980.

1979

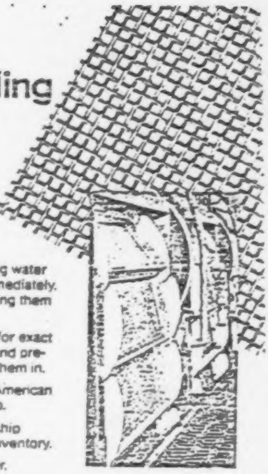
- Power line monitoring program to develop sophisticated optical monitoring techniques to detect failures of overhead lines, as indicated by infrared and ultraviolet light emissions from aircraft—Salt River Project, Phoenix, Ariz. received $20,000.
- Development of a procedure for in-service treatment of extruded type 15- to 35-kv cables to extend the operating lifetimes of underground distribution cables by three to five years, by treating them with dry gas and low molecular weight liquids designed to retard the growth of electrochemical trees—Cable Technology Laboratories, Inc. received $156,000.
- Construction and operation of a Darrieus-type, vertical-axis wind turbine (VAWT) submitted by Oregon municipal utilities and co-ops, represented by the Eugene (Ore.) Water & Electric Board. Manufactured by Alcoa, the turbine will measure approximately 123 feet high by 32 feet wide and provide a generating capacity up to 500 kw. This wind facility will provide important details on the integration of a significant alternative energy technology into a utility grid—Eugene, Ore. received $20,000.
- A technical and economic feasibility study leading to the construction and operation of a cogeneration system fueled by biomass (primarily wood wastes), refuse-derived fuel (from local municipal solid wastes), and coal—Tacoma, Wash. awarded $20,000.
- An evaluation of technical and institutional questions in residential load management with the city of Philippi, W. Va. to determine and document consumer attitudes on and knowledge of electricity use and conservation. An advanced two-way communications metering system will be developed and deployed in conjunction with this project—Philippi, W. Va. received $20,000.

1980

- Investigation of recovery of hydrogen from industrial waste gases and consideration of alternatives for its utilization. Study the economics of hydrogen production and use in publicly owned municipal utilities—Provo, Utah received $18,000.
- Installation and testing of a three-ton Rankine-cycle, solar-powered air conditioner, using heat from flat-plate solar collectors to drive a compressor for residential space cooling—Salt River Project, Phoeniz, Ariz. received $20,000.
- Design an approach for heating a commercial office building with reject heat from the cooling system of a combined-cycle power plant, using heat-pump augmentation to boost temperatures to 100F-140F range—Massachusetts Municipal Wholesale Electric Co. received $20,000.
- Development and demonstration of restaurant-kitchen heat-recovery water-heating systems, using the heat-pump principle for recovering heat from ovens, dishwashers, refrigerator compressors, etc. to provide hot water for food preparation and dishwashing, as well as air conditioning and dehumidification for restaurant kitchens—Los Angeles, Cal. received $10,000.
- Evaluation of a coal-fired atmospheric fluidized-bed combustor with a closed-cycle gas turbine and its possible retrofit in an existing power plant—Springfield, Ill. received $10,000.
- Feasibility study for a cogeneration energy-recovery facility, mass burning up to 2,000 tons of municipal solid waste per day in a dedicated water-wall incinerator with energy recovery as superheated steam with steam extraction for industrial process uses and generation (21 mw maximum) of electricity—Nashville, Tenn. received $20,000.
- Use of advanced desalination techniques to produce 40,000 gallons/day of fresh water from sea water for boiler makeup—Key West, Fla. received $5,000.
- Conversion of a medium-speed diesel engine to burn a mixture of ethanol and #2 distillate—Vandalia, Mo. received $18,900.
- Test and evaluation of two second-generation (eight-kw) wind turbines, developing performance and intercon-

nection data—Easton, Md. received $20,000.

- Onsite generation of electricity from landfill methane gas, recovering gas from a sanitary landfill for combustion in reciprocating engines and, subsequently, in prototype turbine engines with integral compressors—Glendale, Cal. received $20,000.
- Technical, economic and environmental feasibility of using advanced (fluidized bed) combustion technology to burn municipal solid waste and possibly coal in a cogenerating power station—Santa Clara, Cal. received $20,000.
- Pursuit of an integrated municipal energy resource system approach involving refuse, sludge, coal combustion, district heating and cooling, resource recovery, and sewage treatment—Taunton, Mass. received $20,000.
- Demonstrating a cascade-cycle (high temperature) water-to-water heat pump, using a groundwater heat source, for residential space heating. The high-efficiency heat pump will supply 180F-200F water from an artesian well source—Massachusetts Municipal Wholesale Electric Co. received $10,200.



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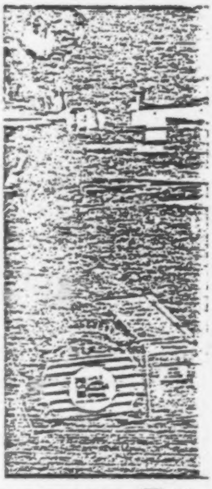

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EXHIBIT D

REGIONAL PLANNING INITIATIVES

There are a number of regional planning initiatives which aid in dealing with financial problems of utilities. Three of the most important are (a) joint action in building power plants, (b) use of transmission to substitute for generation, and (c) power "brokering".

During the past decade, the entire electric power industry has found itself confronted with the serious and fundamental challenges of continuing to provide adequate and reliable electric service at reasonable rates in the face of:

- Higher interest rates
- Uncertain load growth
- Rising fuel prices
- Inflated construction costs
- Recent regulatory delay
- Stringent environmental protection requirements
- Rigorous health and safety rules
- Escalating wholesale power charges

Every municipal electric utility manager is fully aware of the rising cost of bulk power supply which his city buys or generates to sell to its consumers. Short of dramatic and unanticipated technological or economic developments in the field of power production, we will be unable to roll prices back to levels experienced a decade ago. The real question is: how can we slow down the rapid escalation for the benefit of our consumers?

There is no single or simple answer to this question. A number of steps are necessary, including assistance to electricity users in cutting consumption, implementation of cost-effective load management techniques, support for research and development aimed at enhanced efficiency in energy conversion and electric transmission, application of antitrust principles to preserve competition in marketing of fuels, improvement of interconnections and power pooling, administration of the Federal Power Act to curb price gouging and monopolistic practices, use of benefit-cost analysis in evaluating regulatory requirements, and use of joint action to construct the most economic power production facilities. Joint action is one of the most important.

Historically, "joint action" means the pooling of electrical load and financial resources by two or more utilities to achieve bulk power supply which is more economic than any participating single system could realize independently.

Today more than one-half of the nation's 2,200 local public power systems are involved in this type of joint action. Fifty-one joint action agencies --

independent entities organized under State enabling laws -- have been created in 30 States, and bi-lateral contractual arrangements implement joint action in scores of other situations. Efforts range from initial study groups through active construction and operation programs, from two-city interconnections through multi-state endeavors, from purchase of fractions of plants built by others through direct participation in the building of major generating and transmission facilities, and from contractual arrangements through creation of new umbrella organizations which take on major power supply responsibility for their constituents.

What is the case for joint action in the field of bulk power supply? There are a number of factors which dictated this approach for local public power systems.

Let's consider first the situation of public power systems which buy power, and then the facts faced by public power systems which generate power.

Although there are a number of large public power systems such as those owned by the cities of Los Angeles, Seattle, San Antonio, and Memphis -- the bulk of the nation's 2,200 public power systems are small systems which depend on outside sources for their power supply. Indeed, two-thirds of local, publicly owned electric utilities purchase power at wholesale from either publicly owned power marketing agencies or investor-owned utilities -- and such power supply arrangements present a number of current and potential problems in the areas of both availability and cost.

In the case of power supply arrangements with investor-owned utilities (925 public power systems buy all or part of their power supply from private power companies), the problems are the most immediate and in some respects more serious. This is principally because private utilities in recent years have filed an increasing number of wholesale rate increase petitions, at a much faster rate than the Federal Energy Regulatory Commission has been able to review them and determine whether they are fair and reasonable. After a five-month period, the requested increases automatically go into effect until such time as FERC can reach a decision on them. In many cases, the waiting period and review process have lasted for years. The result has been a stacking up -- or "pancaking" -- of successive wholesale rate increases -- some of them going as far back as 1972. This practice of "pancaking" has greatly increased the power costs of hundreds of small publicly owned utilities -- and in many cases, it has placed them in an extremely difficult, if not impossible, competitive position.

In some of those cases, moreover, purchasers of wholesale power from private power companies have been faced with a condition known as "price squeeze" -- a situation that exists when a power company sells power to some of its retail customers at a lower rate than it sells at wholesale to a municipality or other local public power system. A wholesale customer confronted with such a situation obviously has difficulty competing with its neighboring power company.

Over the last decade, the average revenue per kilowatt-hour received by FERC-jurisdictional private power companies for wholesales has increased by 305 percent. During the same period, the average revenue per kilowatt-hour received by these companies for retail sales to ultimate users has increased by only 144 percent.

What about those publicly owned systems which generate power? There are about 675 local public power systems in the United States with generating capacity. Of the total number of systems with generation, 500 have diesel engine sets and 172 have steam plants -- many of which are in small units. While the thermal efficiency of these machines may be high, the economics of today's power production technology work against them.

The price of natural gas burned in diesel sets or steam plants has escalated over 600 percent in the past decade, and present long-term national policy would phase out natural gas as a utility fuel.

The alternate fuel for natural gas is oil. But the price of oil has also risen rapidly -- more than 500 percent in the last 10 years -- and availability is not assured. The Fuel Use Act passed in 1978 as part of the National Energy Act seeks to reduce utility use of oil.

Thus the two conventional fuels for much small scale generation -- natural gas and oil -- are high-priced and of questionable availability.

Diesel engines cannot now use coal, and small steam generation is a victim of scale when it uses this fuel, which is costly to transport and which is burned most economically in large units.

Scale is even more important in the case of nuclear power. There are presently no projected new commercial small nuclear power plants. Indeed, most planned units exceed 1,000,000 kilowatt name-plate ratings. In order to take advantage of low fuel costs currently associated with use of uranium, a large unit is required.

In other words, the two fuels which are now the least expensive or the most available -- uranium and coal -- are either unsuitable for small scale generation or provide optimum benefit in large units.

Here are what we see as some of the benefits which joint action offers in dealing with this situation:

- There are economies of scale in building larger generating and transmission facilities; joint action permits the smaller utilities to take advantage of these economies.

- Joint action gives smaller utilities more options in fuel use and types of generating stations than would otherwise be available to them.

- Joint action allows a smaller utility to avoid putting all its eggs in one basket. It permits an individual system, in effect, to spread its risk by buying pieces of plants constructed over a period of years geared to load growth, rather than sinking its money into a single-shot investment in a plant for its own use over a long period of time.

- Joint action encourages power pooling with its opportunities for economy exchanges and emergency support.

- Joint action may help minimize siting and water use problems by decreasing the number of separate regulatory actions required, by making more efficient use of land, water and other natural resources, and by maximizing support for particular facilities.

- Joint action applies for the benefit of consumers some of the basic characteristics of local public power systems -- non-profit operation, direct public control through elected or appointed officials, application of tax-exempt municipal bond financing, efficient management, and retention of economic benefits by the user-owners.

- Joint action, through a recognized entity representing the interests of a number of smaller systems, may result in improved bond ratings and easier access to financing.

- Joint action permits employment of qualified experts in bulk power supply problems and creation of an organization dedicated to insure availability of "least cost" solutions through coordinated planning.

The growing interest in joint action programs by local public power systems, coupled with a more receptive attitude toward such projects by the investor owned utilities, have resulted in a dramatic growth in joint action programs by local publicly owned electric utilities. One indication of this growth is the amount of financing being undertaken by such agencies. In 1976, for example, joint action agencies issued $965 million in electric revenue bonds. In 1977, they issued $1.7 billion in bonds; in 1978 -- a record year for all public power bond issues -- $2.2 billion. In 1979, $2.1 billion in joint action bonds were issued. In 1980, the figure was nearly $2 billion. The attached table shows the trends.

Why are local public power systems willing to invest these large sums of money? Because of the anticipated economic payoff in lower-than-would-otherwise-be-expected bulk power supply bills.

The potential economic dividend available from joint action by local public power systems was emphasized at the end of last year when the Municipal Electric Authority of Georgia announced that bulk power supply costs for its 47 member municipal electric systems remained essentially level for the fourth consecutive year.

Transmission vs. Generation. The adequacy of reserve margins for electric utilities varies from region to region. Some areas are currently concerned about the prospect of power shortages in the 1980s. However, in the aggregate, the picture is different, as pointed out by a Westinghouse speaker at APPA's 1979 annual conference who cited "overcapacity" as a major utility industry problem and noted that "the cost of carrying excess capacity has brought on some of the financial problems that utility companies are facing." D.D. Danforth, vice-chairman and chief operating officer of the company, told APPA delegates: "We at Westinghouse believe that reserve margin, which now runs to more than 30 percent on a national basis, will remain high throughout the '80s. It will not fall to 22 percent -- the currently regarded optimum figure -- until 1990."

This situation suggests that investment in transmission rather than generation may be the cheapest way for some utilities to acquire needed electrical capacity and energy. Here are a couple of examples:

- Nebraska Public Power District (NPPD) has decided to defer construction of a 650-mw coal plant in favor of construction of the 500,000-volt Mandan transmission line that will link Nebraska, South Dakota and North Dakota with Manitoba Hydro, Canada. NPPD, which expects an annual load growth rate of 3.5 percent between now and 1990, has estimated it will need additional capacity in the mid to late 1980s. The Mandan line is scheduled to be completed in 1986 or 1987. The transmission line will cost an estimated $612 per kilowatt compared to the coal-fired plant's per kilowatt cost of $1,570. NPPD said it will continue limited activity on the coal plant in order to retain the site for a future project.

- Jacksonville Electric Authority is involved in a project with Florida Power and Light Company to build two jointly owned 500,000 kv transmission lines into Georgia which will enable both utilities to purchase coal-derived power from the Southern Company, resulting in a 50 percent reduction in oil use by JEA. Ultimately, JEA will receive 600,000 kilowatts over the lines, offsetting oil which is approaching $35 a barrel and escalating.

Transmission Benefits Available. Full and fair access to transmission -- the "superhighways" of the electric utility industry -- for the purpose of selling, exchanging, delivering, wheeling, pooling, or coordinating electric energy, and joint planning to achieve it, would help accomplish these benefits -- all of which have been identified in DOE's national power grid study:

- Insure equality of opportunity to all electric utilities to engage in transactions which allow access to economies of scale in electric power generation and transmission.

- Stimulate interest in and development of renewable and/or dispersed energy resources which must be integrated into utility systems to make them economic.

- Assist smaller power systems with generation in making the transition from oil and natural gas to coal, nuclear, and renewable resource facilities, as called for by national policies.

- Encourage development of non-utility sources of electrical energy which may supplement national supplies.

- Aid in slowing down rate increases to consumers.

- Help protect against possible power shortages.

- Permit infusion of additional capital into financing of required plants and transmission.

- Save natural resources by making better use of existing facilities and by encouraging more comprehensive planning for future facilities.

- Support efforts to improve power supply by states which have authorized joint action programs by local public power systems.

- Enhance competition in the field of bulk power supply.

Examples Reveal Advantages. An example of what the planning, building, and coordination of transmission facilities can accomplish in a region is presented by the New England Power Pool. The current form of NEPOOL follows proceedings initiated by consumer-owned utilities in many forums, including FPC, the Securities and Exchange Commission, and the former Atomic Energy Commission. Today a large number of small municipal electric systems are active participants in NEPOOL, and are beneficiaries of fractional shares of large nuclear powerplants, the output from which is moved for them over lines of private power companies. Although they fought against inclusion of publicly owned electric utilities in the program, private power companies now call the group effort a success. James Tribble of the New England Electric System described the progress being made under the agreement this way:

> *"The Pool has operated successfully since 1971. Reliability and economy have been improved markedly by central dispatching. Economics of scale are being realized as numerous jointly owned generating units are committed and inter-pool purchases arranged. Membership in NEPOOL has grown to include over 50 utilities having over 98% of the total New England load. This record of success is expected to continue in the future."*

MEAG Approach Successful. It is sometimes suggested by opponents of Federal authority to order transmission and coordination that this would be disruptive, threatening adequacy and reliability of service. There is, of course, no need for this to be so. An example of such a transition is currently provided by experience in Georgia.

In 1972, the 50 municipal electric systems in Georgia decided that the soaring cost of wholesale power and lack of assurance of future supply dictated that they get into the business of generating electricity. The Georgia Power Company had opposed such efforts in the past. In 1974, faced with antitrust review of its activities at the Nuclear Regulatory Commission, the company decided that joint ownership with its wholesale customers was a better course to follow in meeting power needs, and agreed to sell the municipals portions of the company's generating capacity and transmission system. In 1975, the Georgia legislature passed legislation creating the Municipal Electric Authority of Georgia. In 1976, MEAG and Georgia Power signed agreements providing for joint ownership and operation of certain generating and transmission facilities. In 1977, MEAG purchased 17.7 percent of the company's 2,320,000 kilowatt Vogtle Nuclear Plant, 17.7 percent of the 1,630,000 kilowatt Hatch Nuclear Plant, 10 percent of the 1,730,000 kilowatt coal-fired Wansley plant, and 10 percent of the 3,240,000 kilowatt coal-fired Scherer plant. Some 885 miles of transmission lines, and 53 substantions were bought from the company. Under the terms of an integrated transmission system agreement, MEAG has pledged to purchase facilities proportionate with its share of the load on the system of the company, which will transmit for the cities. Total investment by MEAG by 1985 is expected to be more than $1.6 billion. When every unit is operational, MEAG's share of the output still won't be sufficient to supply all the requirements of its participants. Then, as now, MEAG will purchase from other sources.

In less than five years, the 50 Georgia municipals serving a combined population of 500,000 persons moved from wholesale customers to major power suppliers -- without destroying the adequacy or reliability of the State's power supply but rather enhancing both. At a time when capital accumulation for capital expansion is alleged to be a significant problem, Georgia's municipal electric systems are making a massive infusion from sources unavailable to the company for facilities to serve their own needs. The operation is economically and technically feasible, and benefits consumers of the cities.

Northwest Planning Aids All. In the Pacific Northwest, availability to all utilities, regardless of ownership, of the extra-high voltage transmission grid owned and operated by the Bonneville Power Administration allows coordinated movement of power in a manner benefitting every electric system, large or small. Economies of scale are accessible throughout the region because the arrangement stimulates planning and coordination.

Under the Federal Columbia River Transmission System Act of 1974, the Bonneville Power Administration, which markets power from Federal resources over 12,500 circuit miles of BPA transmission lines, is charged with operating, maintaining, improving, and replacing its transmission system so as to (a) integrate and transmit power from existing or additional Federal or non-Federal generating units, (b) provide service to BPA customers, (c) supply interregional transmission facilities, and (d) insure the electrical stability and electrical reliability of the Federal system. "The Administrator shall make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States," the statute states.

Because of the existence of the Pacific Northwest-Southwest intertie -- a major electrical link promoted by the Department of the Interior and built and operated by Federal, non-Federal public, and private utilities -- consumers as far apart as 1,000 miles may find that they are saving money as the result of power interchanges. Thus, low-cost hydroelectric power from the State of Washington could displace high-cost oil-fired generation in Southern California with enhanced revenues to aid BPA in the Northwest and more reasonable bills to help consumers in the Southwest.

The 1970 "National Power Survey" issued by the FPC stated both the problem and the solution in two brief paragraphs:

> *"Simultaneous outages of major generating plants, delays in placing new generation in service on schedule, fuel shortages, and unforeseen power demands have jeopardized or degraded bulk power supply in some sections of the country. Overall system stability must be protected at all times in spite of these difficulties, so there is need to provide large blocks of economic and reliable generation, and to provide transmission networks capable of transferring large amounts of power from one area to another.*
>
> *"The electric utility industry can achieve full coordination, without altering its pluralistic character, by coordinating the*

> *planning, construction, and operating activities of all utility groups in areas with loads of sufficient size to realize all the potential benefits of modern technology for assuring adequacy and economy of power supply. Certainly, from both the resource conservation and economy of service viewpoints, coordination among all of the utilities within the respective regions should be a major objective."*

Anti-Competitive Actions Checked. Availability of both long and short term opportunities are necessary to allow smaller systems to secure optimum bulk power supply arrangements. Although progress has been made in many regions in recent years in assuring better coordination and pooling of all utilities, there are still cases of smaller systems being denied access to transmission and coordination where there is no economic or technical justification for such action. Anticompetitive motivation should not be allowed to decide the issue. Basic fairness means that all utilities have an equitable chance to take part in activities necessary for economic survival.

In 1970, the Atomic Energy Commission was given the duty to scrutinize each application for a license for a nuclear power plant to determine whether granting the license "would create or maintain a situation inconsistent with the antitrust laws." Over the last 10 years, the AEC and its successor agency, the Nuclear Regulatory Commission, have found a number of instances in which it has found it necessary to condition a license on agreement by the applicant utility to supply transmission services which it had previously denied to smaller systems for anti-competitive reasons. In major cases involving the question of transmission, the NRC:

- Found in the case of five private power companies in Ohio and Pennsylvania seeking a license for the Perry project that the companies exhibited increasing dominance of the bulk power services market -- a trend which an Atomic Safety and Licensing Board found "has not been passive or accidental but has been the result, at least in part, of policies such as refusing to engage in third party wheeling, emergency interconnection, or reserve sharing...."

- Asserted in a decision by the NRC Appeal Board that the refusal of a private power company in Michigan to "wheel" power had an anti-competitive effect, that the applicant's "refusals to coordinate with small utilities were both unreasonable and anti-competitive," and that the company excluded small utilities from the Michigan Power Pool -- another factor which was considered "indicative of its anti-competitive intent to exclude small utilities from coordination."

In both these cases, as in others, licenses were conditioned to cure the abuses. However, the problem has been widespread, and cannot be dealt with in even this time-consuming manner absent an application for license to build a nuclear power plant. Private power company lobbyists have been successful in defeating a legislative proposal to apply the NRC approach to fossil-fired facilities, and suits under antitrust laws take sufficiently long in the courts that the patient may be dead before the remedy is prescribed.

Control of transmission can give a utility a make-or-break grip over another utility which seeks support or access to other suppliers. By setting arbitrary conditions or unreasonable prices, the utility controlling transmission can make impossible conclusion of agreements which may be of substantial advantage to a smaller system and to the public. Transmission control can be employed to kill or cripple a competing utility. Broad Federal responsibility to initiate action to solve these problems and to assure fair answers is needed. Utilities are granted special powers by government to condemn land for transmission rights-of-way and use public thoroughfares to move electricity; it would seem that the public has a clear interest in insuring that these powers are not used to promote monopolistic practices.

Ready access to transmission facilities on equitable terms has a beneficial effect on competition in the electric utility industry. Competition, in turn, benefits consumers through more efficient service and lower prices for electricity. Not only do electric utilities compete head on for new loads on the outskirts of service areas and for industrial loads whose decision to locate in a particular area may rest on energy costs, but there is also a valuable yardstick competition which exists between neighboring utilities -- the competition which is felt by utilities when their performance is measured by consumers against the performance of other utilities.

The key to successful competition, however, is low-cost bulk power supply and in many instances the availability of low-cost bulk power is dependent on whether there is competition among bulk power suppliers. As James Fairman and John C. Scott pointed out in the May, 1977, issue of the Hastings Law Journal:

> *"Ability to compete is directly related to ability to minimize cost. By far the largest portion of an electric utility's costs are incurred in procuring bulk power supply. A utility may obtain bulk power supply by constructing its own generation and transmission facilities, by joining with other utilities to construct generation and transmission facilities, or by purchasing power from another utility.*
>
> *"While a large utility can realize economies of scale by building a generating unit to serve only its needs, small utilities must rely on less efficient and less economical small generating units if they build to serve their own needs. They can, on the other hand, realize both cost and reliability benefits through interconnection of transmission facilities, pooling of generation facilities, and regional coordination and planning. However, it is difficult for many small utilities to obtain access to these cooperative activities.*
>
> *"A competitive problem may also arise when utilities which are unable to obtain benefits from power pooling seek to purchase power at wholesale from other utilities. When a wholesale supplier is dominant in an area, a purchaser is limited in choice of suppliers unless the dominant supplier will agree to transmit electric power from another source. If he will not so agree, the purchaser may be forced to accept contractual restrictions or wholesale prices that thwart its future ability to compete with the wholesale supplier.*

> *"Thus, the small system problem of access to low-cost bulk power supply is most easily met by allowing utilities access to power pools or to transmission services. The former would permit joint ownership and decisionmaking. The latter would permit a choice among wholesale suppliers."*

PURPA Problems Cited. Federal authority is required to ensure that the existing transmission system is used to promote fairness and efficiency in the provision of electric service to all consumers.

The National Energy Act, specifically section 203 of the Public Utility Regulatory Policies Act (PURPA), provides one appropriate forum: the Federal Energy Regulatory Commission. The expansion of FERC's authority to order "wheeling" -- the movement of electricity by one utility for the account of another -- by the 95th Congress was a needed reform although some of the Congressionally imposed restrictions contained in PURPA are not consistent with the goals of conserving resources, making efficient use of facilities, and providing consumer equity.

For example, section 203 of PURPA states that before it can order transmission of wholesale electric energy the Commission must find that the electric utility being asked to wheel has given notice that it is unwilling to or unable to provide electric service to the utility requesting the transmission. This provision provides no real relief if the utility which has been asked to wheel power agrees to provide electric service but only at an axhorbitant rate, thereby depriving consumers of a less expensive, perhaps more reliable source of electricity.

Another unnecessary restriction contained in section 203 restricts FERC's power to order wheeling when the electric energy being wheeled would replace electric energy required to be provided pursuant to a contract. It should be noted that this includes situations in which the utility being asked to wheel is not the utility which is providing the alleged replaced electricity. The existence of a contract is irrelevant to the question of whether wheeling is justified on economic and reliability of service grounds, and has anti-competitive overtones. Contractual disputes, if they arise, should be dealt with as they are in every other area of commerce -- by the courts.

A similar provision restricts the Commission from ordering a utility to wheel when it would replace energy which the utility is currently providing under a rate schedule on file with FERC. This provision has no justification as a rate schedule should only set rates and not, as is attempted here, lock a utility into a purchase relationship which may be disadvantageous to its consumers.

Finally, the Commission is not permitted to order wheeling unless it finds that the order will not likely result in a reasonably ascertainable economic loss for any electric utility. This vague standard is not necessary to protect utilities who will be paid for the transmission service they provide, and will serve only to stimulate litigation and delay consumer receipt of benefits.

APPA believes that the restrictions which we have identified are inconsistent with the national energy goals and urges that these restrictions be eliminated.

Incentives for Voluntary Action. In addition to the Federal authority to require that certain steps be taken in order to ensure coordination and the equitable sharing of transmission, there is a need for examination of incentives which might encourage voluntary achievement of that end.

A start would be a national effort to identify the simple actions which could be taken to encourage efficient use of transmission and generation resources and bring down the cost of electric service. For instance, public exposure provides a strong incentive to action.

Other incentives might include an exemption from certain environmental regulatory review on a showing, for instance, that the increased coordination of electric facilities to be derived from new transmission capacity would have a net environmental benefit. It might be possible to provide accelerated permitting procedures for transmission lines across public lands to those sponsoring agencies which express a willingness to plan for regional needs and to provide equitable access to other utilities. Or there might be exemptions from curtailments of fuel if a utility can demonstrate it is interconnected to provide back up service to another utility. Perhaps loan guarantee programs and priority in receiving Federal coal leases or access to other resources could be offered to systems that were open to coordination and cooperation.

There are a number of specific additions to the existing transmission grid which it might be prudent to construct. Many APPA members believe the intertie between the Missouri River Basin and the Pacific Northwest should be strengthened. The Three Mile Island incident and the recent shutdown of five nuclear power plants to review protection against earthquakes demonstrate the possibility of nuclear shutdowns on a wide scale. If this should happen in the Northwest in a future year when hydroelectric production was down due to low water, there could be insufficient transmission capacity to supply power from states such as Colorado, Wyoming, and Montana although large supplies of coal could be immediately at hand.

Additional lines should be constructed into Florida, which is relatively isolated from the rest of the country. As it stands now, if there were a shutdown of nuclear plants in Florida and a short supply of imported oil, Florida would be on its own with limited possibility of importing the necessary power.

Publicly owned systems in the Rocky Mountain and Southwest regions of the United States believe that there is a need for more north-south transmission capacity. The additional capacity could be used to increase reliability, to take advantage of seasonal diversity, and to permit the development of new resources in those regions.

In view of the difficulty of obtaining new rights-of-way, it would make sense to upgrade the existing Federal transmission system where it already exists by changing 230 kv and 345 kv transmission lines to 500 kv lines, or higher voltages, as suggested by the Bonneville Power Administration. For example, the rights-of-way which carry the 16,000 circuit miles of transmission operated by the Western Area Power Administration, the Federal agency which markets power from Federal generating facilities throughout many of the western States, might provide the siting solution for necessary transmission capacity of the future. The benefits of added carrying capability on the same right-of-way would include cost savings, land conservation, and esthetic enhancement.

Analyzing Benefits/Costs. Over the years, a number of studies have shown the major net dollar benefits available from interconnection and coordination of utility systems through inter-linking transmission. Some recent examples:

- The Senate Subcommittee on Energy Conservation and Regulation received testimony during hearings held in September, 1977, which revealed that if the Texas utility pool, ERCOT, was interconnected with Louisiana and with the five states which make up the Southwest Power Pool, the savings between 1975 and 1980 would have been between $600 million and $2 billion.

- According to the Bonneville Power Administration, a contracted transfer of surplus hydroelectric power from the Pacific Northwest to the Pacific Southwest over the high-voltage NW-SW intertie resulted in an annual savings of 15 million barrels of oil from August, 1976, to August 1977. At 1977 prices, this amounts to $216 million which were not exported to the OPEC nations.

- A 1975 Federal Power Commission study estimated that the effect of full interconnection and coordination of electric systems in Kansas and western and southern Missouri would result in a total savings of $1.92 billion over the eleven-year period between 1980 to 1990 as opposed to a continuation of current operating practices. The savings in this instance would result from a decrease in oil generation costs and an increased reliance on coal.

A transmission line is much like a highway. Once it is in place it will be used in ways that may not have been contemplated, but are nevertheless highly desirable. This factor as well as other social and environmental factors should not be obscured by strict or initial cost/benefit calculations.

Charles Luce, former Administrator of the Bonneville Power Administration and Under Secretary of the Department of Interior and current Chairman of the Board of Consolidated Edison, made this point about transmission in a talk in 1978 at Reed College in Oregon.

Noting that Federal hydroelectric projects in the Pacific Northwest turned out to be "a gold mine" in terms of benefit to cost ratios, he asserted that the Pacific Northwest-Southwest intertie is the "mother lode." "Thus far, in 10 years of operation, the PN-PSW inter-regional connection, in addition to other benefits, has saved almost $1 billion in fuel oil that California utilities did not have to burn because they could substitute Northwest secondary hydro that otherwise would have been wasted to the sea," he said. "Considering the benefits already accrued, and those that can reasonably be anticipated over the 50-year life of the lines, principally the sale of secondary energy and diversity/capacity exchanges, it will on average repay its entire capital cost of $600 million for each of the 50 years. Discounting the costs and benefits at 8 percent -- not the 3 percent we used in the original analysis -- its cost-benefit ratio is now about 1:11." One of Luce's conclusions: in the selection of projects, cost-benefit analysis is a good starting point, but it is not a substitute for social and political judgment.

Energy Brokering. The concept of utility trading in electricity is one which has a dollars-and-cents payoff for consumers. Local public power systems are involved in the implementation of this idea, as is described in the attached article from Public Power.*

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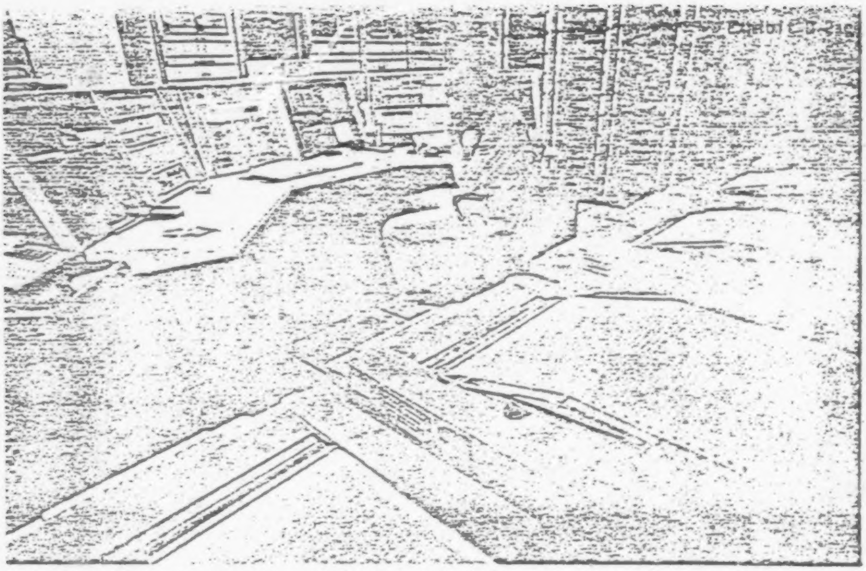
*According to the [illegible] Power [illegible] contracted [illegible]



Each utility participant in the energy broker system is connected with the General Electric Information Services Company's control center which, manned by a technical staff 24 hours a day, aids the utilities by rapidly gathering and analyzing information about their hourly generation costs. Photo courtesy of General Electric Information Services Co.

Energy broker saves kwh for Florida munis

by **PAMELA A. NAZARUK** *assistant editor, PUBLIC POWER*

YOU'VE HEARD OF A STOCKBROKER, but have you ever heard of an energy broker?

A stockbroker, by trading stocks and bonds for his clients, tries to make a profit for them. An energy broker also trades to make profits for clients, but the product traded is low-cost electricity.

An energy broker is generally a machine—a shared computer program/communication system. A broker system could be operated by individuals, but that would take too long. With an energy broker, profits are realized for a client—a utility—when it sells low-cost electricity it is producing for another utility. Savings to the recipient utility derive from avoided cost; electricity is purchased for less than cost of generation by the purchaser.

An energy brokering system is successfully working for 11 municipal and three investor-owned electric utilities* in Florida in conjunction with the Tampa-based Florida Electric Power Coordinating Group (FCG). All are tied into a remote, central (time-share) computer system in Ohio. The computer handles the calculations for buying and selling generated electricity on a least-cost basis.

New Smyrna Beach (Fla.) Utilities Commission, with about 136,166 mwh sales a year, is one of the smaller systems on the energy broker system. New Smyrna Beach is achieving some of the greatest savings, proportionally, of any of the participants. Over the first 19 months of participation, June 1979 through December 1980, New Smyrna Beach saved $389,583 by selling power to other utilities through the energy broker and purchasing power when

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The 11 public power systems are Fort Pierce Utilities Authority, City of Gainesville, City of Homestead, Jacksonville Electric Authority, Lakeland Department of Electric & Water Utilities, Lake Worth Utilities Authority, Orlando Utilities Commission, New Smyrna Beach Utilities Commission, Sebring Utilities Commission, City of Tallahassee and Vero Beach Municipal Utilities. The three private power companies are Florida Power Corp., Florida Power & Light Co. and Tampa Electric Co.

buying was more economical than generating at a higher cost.

During this time, New Smyrna Beach sold 36,273 mwh to other utilities for a net profit of $351,104 (over fuel costs of generating this energy) and purchased 3,131 mwh for a savings of $38,479.

The energy broker concept maximizes savings across Florida attainable from hourly economy (non-firm) interchange transactions using on-line generation. Through this process, in the year ending September 1980, 13 municipal and investor-owned utilities saved $40 million by interchanging 2.4 million mwh.

Participating utilities have individual agreements with other utilities on the broker system and are linked to a General Electric time-share central computer. Through their local telephone systems the utilities are linked to a communications network. Every hour the computer determines the most economical interchanges of power among the utilities from information transmitted by each utility on a remote data terminal.

How the Broker Works

"The basic principle is that the highest-cost buyer is matched with the lowest-cost seller and so on until the cost spread is almost zero," said Donald Benjamin, FCG staff engineer and broker coordinator.

Every hour each utility tells the computer the amount of power it wants to buy or sell, as well as the current cost of generating its own power. A utility's dispatcher can enter one of four quotes:

- a buy-and-sell quote;
- a sell-only quote;
- a buy-only quote; or
- no quote, meaning that under system conditions the utility cannot enter a quote for the upcoming hour's calculation of transactions.

The computer analyzes this information and, 20 minutes before each hour, sends a printout to each utility, matching buyers and sellers according to maximum *total* savings. It considers all current interchange and transmission service agreements, applicable wheeling charges and loss percentages, and allocation of third-party wheeling costs between buyers and sellers. Wheeling costs between all municipals are split between buyer and seller, but if an investor-owned utility is involved in the interchange the buyer pays all wheeling expenses, according to Jim Boyle, assistant manager of New Smyrna Beach system operations.

A particular match will be conceived by the computer if:

(1) proper interchange agreements are in place;

(2) the seller's profit—the transaction price minus the seller's price minus any seller-paid wheeling costs—is greater than or equal to $1/mwh; and

(3) the buyer's savings—the buyer's price minus the transaction price minus any buyer-paid wheeling costs—is greater than or equal to $1/mwh.

These matches are sorted in descending order, starting with the match with the greatest total spread (highest buy quote matched with lowest sell quote).' The system is designed to maximize economy interchange savings on a statewide basis.

Benjamin explained the process:

Walter Allen, New Smyrna Beach Utilities Commission power coordinator, studies generation data to determine how much power should be bought or sold in the next hour on the Florida energy broker system. The utility has saved $389,583 since first joining in June 1979 with other utilities in the Florida energy broker program.
Photo by Martha Draper, Daytona Beach News-Journal.

"Economy interchange takes place when two utilities take a look at the costs to produce, say, an additional 100 mw of energy. Cost in this case directly reflects the expenses for producing just that additional increment of energy. This cost is not based on the average generating costs of the utility but is instead the 'incremental' or 'marginal' cost.

"Utility A may be able to generate an additional 100 mw at an incremental cost that is much lower than utility B's decremental or "avoided" cost for that same amount of electricity. So utility B, needing energy to meet its customer's demands, agrees to purchase 100 mw from utility A. The purchase price per mw is the dollar amount exactly halfway between utility A's incremental cost and utility B's decremental cost. Therefore, the economy interchange transaction is satisfactory to both utilities. The amounts that A profits and B saves are identical.

"The complication arises when you have 14 utilities constantly interacting, with each utility buying and/or selling different amounts of electricity at widely varying prices."

But there are no losers, only winners. Every utility saves.

Benefits of Brokering

In the first year of operation, the participants saved $24.4 million by interchanging 2.1 million mwh. In the second year of operation savings increased 33 percent.

In addition, members reap important operational benefits:

- **Simplification of transactions:** It is very difficult to analyze manually all the economic considerations necessary to optimize savings on an hourly basis, considering the complexity of all possible matches. The broker calculates the optimal schedule of transactions and automatically returns the recommended schedule to the utility dispatchers, minimizing inefficiency and possible mistakes.
- **Impetus for system economics:** Since the broker works on an hourly schedule, the utility dispatcher is forced to look at his system's economics on a more regular basis. Previously, many systems made economy transactions sporadically, only when the advantage was easily foreseeable.
- **System generation planning:** Forced to look ahead on a regular basis, the utility dispatcher plans better and uses system generation more [illegible].

ECONOMY INTERCHANGE

UTILITY A	UTILITY B
Cost of next 10 mw = $30/mwh Cost of last 10 mw = $25/mwh	Cost of next 10 mw = $20/mwh Cost of last 10 mw = $15/mwh
therefore UTILITY A	therefore UTILITY B
can sell 10 mw @ $30/mwh or can buy 10 mw @ $25/mwh	can sell 10 mw @ $20/mwh or can buy 10 mw @ $15/mwh

UTILITY A
BUYS
UTILITY B
SELLS

Since Utility B's incremental cost is less than Utility A's decremental ("avoided") cost, B sells 10 mw to A.

Transaction Price = ½($25 + $20)
= $22.50/mwh.

Utility A reduces generation by 10 mw and saves:

Amount purchased (avoided cost − transaction price) =
10 ($25 − $22.50) =
$250 − $225 = $25

Utility B increases generation by 10 mw and profits:

Amount sold (transaction price − generation cost) =
10 ($22.50 − $20) =
$225 − $200 = $25

- **Coordination among utilities:** The broker system induces participating utilities, both municipal and private, to provide electricity economically. Efficient utility conservation delays costly new power plant construction.
- **Reduced use of oil:** Florida utilities are very dependent on oil-fired generation, but through the broker they can use the most economical fuel generation, such as nuclear and coal, first.
- **Reduced equipment cost:** Although energy brokering requires the use of a centralized computer, the individual cost per utility for new equipment is minimal. The utility, when entering into the broker system, leases a remote computer terminal which is installed in its operations office. As an example, New Smyrna Beach's monthly costs before purchase of a teleprompter included $100 for a leased teleprinter and $225 for base assessment for broker operating costs, plus any additional expenses based on the amount of broker participation. Therefore, total monthly costs of brokering for New Smyrna Beach average about $415.

Origin of Florida Broker

The initial concept of energy brokering for the Florida utilities began in September 1977 at an FCG committee meeting. A task force studied the concept and visited three power pools in the Northeast: New York Power Pool, New England Power Exchange, and Pennsylvania-New Jersey-Maryland Power Pool.

Recommendations for operating a broker system were implemented in a one-month test period in March 1978. Analyzing the benefits and performance of the test, the task force found the broker concept could provide additional savings beyond the then-existing economy interchange method in use by some utilities on an individual basis since the early 1970s.

As a result of the test period, various recommendations were made for system operation including:

- a letter of agreement for funding the broker should be signed by any generating utility desiring to participate:
- a subcommittee should guide the coordinated brokering effort;
- [illegible] be selected to provide coordination, guidance and assistance to the participating utilities;
- a centralized broker office should be established; and
- initially, a time-sharing computer should be used until enough experience is gained to purchase a system.

A timetable with a completion date of Feb. 1, 1979, was developed and an energy broker coordinator was selected. After software needs were determined and developed, a user instructional manual was completed and sent to participating utilities. A "hands-on" workshop was conducted Jan. 25 to show dispatchers how to use the energy broker. And at noon Feb. 1, the automated energy broker began official operation on schedule.

The energy broker has since continued operation without any major difficulty. The computer system missed only 45 hourly schedules out of 8,459 hours of possible operation the first year, yielding a 99.47 percent availability. The period of nonfunction was caused by maintenance downtime—six hours each week—for the General Electric main file system—[illegible] an alternate broker system is available during such periods.

DOE and PSC Involvement

The Florida Public Service Commission (PSC) is very supportive of the broker system. During its original conception the PSC changed its fuel adjustment formula to increase possible savings resulting from economy interchange. Previously the formula set very limited guidelines hindering interchange benefits.

Support has also come from the Department of Energy (DOE). It is monitoring results of the Florida program. Last year, to encourage the broker concept, DOE sponsored five seminars, based mostly on the Florida program, said Jim Barker of DOE. Two of the seminars were designed for regulatory commissions, two for interested utilities and one for the federal government. A broker conference is scheduled for April in New Orleans, according to Barker.

"DOE has strongly encouraged other electric utilities to look at the brokering system in Florida and determine whether [illegible] tunity for increased economy," said Barker.

Four other organizations use energy brokers: Mid-Continent Area Power Pool, which has been in operation for a few years; South Texas Group and Western Systems Coordinating Council, which both utilize the Florida computer program; and MOKAN, a group of utilities in Missouri and Kansas which developed its own program. This spring, Mid-America Interpool Network plans to implement an energy broker system.

With interest in energy brokering growing nationwide, the FCG has offered to make its program available to new brokering groups. This saves the new groups time and money by eliminating design of totally new computer programs.

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OVER 90 PARTICIPANTS FROM OWNERS, A/E's AND CONTRACTORS HAVE SAID:

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- PROJECT MANAGER: A/E FIRM "An organized common sense approach with a good sequence of topics and reinforcement of concepts"
- CHIEF PROJECT ACCOUNTANT: ELECTRIC UTILITY "Helped me understand technical approaches and issues"
- SUPERINTENDENT OF CONSTRUCTION: ELECTRIC UTILITY "Performance orientation and measures of accomplishment very useful; good blend of utility and engineering and construction know-how"
- PROJECT MANAGER: A/E-CONSTRUCTOR "Well organized; practical ideas; good discussions with owner personnel"
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CHICAGO: MAY 11-13, 1981

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EXHIBIT E

FUEL MIX CONSIDERATIONS

There are a number of fuel-related Federal policies and programs which are adversely affecting local public power systems. Here are some of them:

Prohibition on Utility Use of Natural Gas. The restrictions of Sec. 301(a) of the Fuel Use Act on utility use of natural gas are a political anachronism. They were enacted at a time when natural gas was considered to be a disappearing fuel. But natural gas supplies are now relatively abundant and projections by authoritative sources for future supply are very optimistic. A sense is developing among some supply experts that gas may even by the "boom fuel" of the 1980's.

In this circumstance, the national interest in cutting petroleum imports has forced administrative action of the last two years to permit utilities to increase gas use in order to displace petroleum, acknowledging that the prohibitions of existing law force utilities to resort to imported oil and do not serve the public interest.

Limiting utility use of gas does not protect supply for other classes of users: under both Federal and state gas curtailment plans large boiler fuel gas use is the first curtailed and the last served. Utilities receive gas only after all residential and commercial, and most other industrial requirements, are satisfied. Current national policy permits unlimited growth for high priority natural gas users. Holding gas in the ground for future use by high priority consumers would not protect them from shortages; it would make shortages more likely, by inhibiting exploration. The proceeds from the sale of gas from productive wells are used to finance the drilling of exploratory wells. Thus, producers cannot husband gas from productive wells.

The Act's prohibition on utility use of natural gas after 1990 will have the following effects: first, utility use of petroleum will be increased. Generating units which can only use gas or oil will be forced to use oil; in those parts of the country which have historically been dependent on gas generation, this use of oil will be very substantial.

Second, a large portion of the nation's oil and gas-fired benerating plant will have to be retired prematurely, thus imposing an extremely serious rate burden on consumers, and a capital burden on utilities, who must pay for this waste of equipment and for new replacement capacity.

Third, the capital requirements facing the utility industry, already huge, will be increased even more. Utilities are moving as rapidly as possible to build coal, nuclear, and other alternate fuel-fired facilities both to replace existing gas/oil capacity and to meet load growth. This burden is coincidentally heaviest in some gas-dependent regions which happen also to be experiencing fast population and industrial growth. Utilities are already accomplishing significant oil savings, and will achieve major reductions in both oil and gas use over the next ten to twenty years. But even with the enormous expenditures now planned, a significant amount of generating capacity which can use only oil or gas will and must remain in use after 1990. For that capacity, utilities can either cut their oil use, or their gas use. They cannot cut both.

APPA believes that a national policy preferring the use of imported, costly, and relatively scarce petroleum, over mostly domestic, less expensive, and more abundant natural gas, is irrational. The Fuel Use Act should be amended to repeal the prohibitions of Section 301(a) on utility natural gas use.

Problems with Nuclear Power. Local public power systems have a strong stake in a healthy nuclear power industry. Thirty-three publicly owned electric utilities -- including joint action organizations which represent the interests of a number of systems -- hold equity ownership in 14.6 million kilowatts of capacity in 36 nuclear power units, and scores of others have purchased entitlements to the output of nuclear stations or buy power at wholesale from utilities with direct nuclear involvement.

Availability of nuclear power will help keep a damper on rising rates for electricity, decrease the necessity of relying on fossil fuels with their environmental and availability problems, and add desirability diversity to the nation's generation mix. If nuclear power is to retain and expand the power production position to which it is entitled on the basis of its economic performance, these steps need to be taken:

1. Streamline the licensing process for nuclear power plants. There is a bottleneck at the Nuclear Regulatory Commission in the processing of operating licenses. Evidence presented to a House appropriations subcommittee earlier this year showed 13 units affected, for a total delay of 90 months. The costs of delay to affected utilities and their consumers run about $30-$30 million a month, including the cost of interest paid during construction and the cost of replacement power. While the plants involved are being built by private power companies, a number incorporate consumer-owned utility partners. Congress should give its support to attempts to speedup the handling of licenses while preserving necessary health and safety and competitive protections.

2. Implement a positive program to deal with spent fuel and radioactive waste. Technical experts say that the means exist to store safely residual remains of nuclear fuel, but policymakers have not been able to get together on a procedure for implementing the answers. Spent fuel rods continue to pile up in the storage pools of reactor operators, and the question of creating permanent depositories for both the low-level and high-level radioactive waste associated with nuclear power plants is seemingly the subject for debate but not decision. Failure to solve the dilemma will retard the growth of nuclear power. Congress should move forcefully to formulate and submit to Congress a program which will move toward resolution of the radioactive waste disposal problem.

Hydro Has Potential. Public power systems are exhibiting a keen interest in expanding their existing hydroelectric projects, building new ones, or cooperating with others who seek to do so. Why the public power interest in hydro power?

One reason is that high fuel prices have become the driving force in utility economics -- and the basis for customer complaints about high bills. During the past 10 years, electric rates -- spurred by soaring fuel costs -- have overtaken and passed the cost of living. From September, 1970, to September, 1980, the retail price index for electricity jumped 152.7 percent, compared with a 114.4 percent increase for the Consumer Price Index.

Electric utilities which rely on their own generation are currently finding that, in extreme cases, fuel costs may represent as much as 80 percent of operating and maintenance expenses, which in itself constitutes about two-thirds of the delivered cost of electricity.

Obviously the "inflation-proof" fuel -- falling water -- looks very good to many public agencies now in the power generation business. And systems which do not now generate are also finding it prudent to examine hydro power because the same high fuel costs are showing up in their wholesale purchase rates.

Small-scale hydro electric projects have special appeal for local public power systems, because most of them are small; an estimated three-fourths are located in communities of 10,000 persons or less. A low-head hydro development may be the "appropriate technology" for such towns, which frequently prize the virtues of local control and self-help. In addition, such projects recommend themselves because of their relatively short construction lead-time with known techniques; potential long plant life; possible decreased transmission requirements; multiple-purpose character fitting in with other local needs, such as water supply, flood control, wildlife enhancement or navigation; environmental advantages stemming from a lack of air and water pollution plus elimination of storage of fuel and combustion waste; opportunities for remote control; and low outage rates and high reliability.

There is a lot of hydroelectric potential -- an estimated 113.7 million kilowatts -- left undeveloped in the U.S., and many of the sites with engineering, economic, and environmental feasibility which generate electricity in the future will be developed by entities other than local public power systems.

There is, for instance, a major opportunity for expansion of the Federal hydroelectric system by installation of additional capacity at existing dams with present power production capability, by added turbine-generators at dams which have not previously produced power, and by building new dams which encompass power generation equipment. In its Western Energy Expansion Study, the Bureau of Reclamation identified and recommended for study 27 site specific proposals totalling 1.2 million kilowatts to uprate existing units, add to present power plants, build new facilities, and develop low-head facilities -- plus another seven suggestions for 10 million kilowatts of pumped storage capacity. A program is already underway in the Pacific Northwest to add to the generating ability of dams of the Corps of Engineers and the Bureau of Reclamation. Additional generating capacity is under construction by the Corps in the southeastern part of the U.S., and planning continues on the Dickey-Lincoln School project on the St. John River in the State of Maine.

The Corps' 1977 study "Estimate of National Hydroelectric Power Potential at Existing Dams" suggested that an additional 54.6 million kilowatts of capacity could be achieved by (a) installing more efficient turbines and more powerful generators at existing hydropower dams, (b) adding additional turbines and generators to existing hydropower dams, and (c) constructing powerhouses at all existing non-hydropower dams in the U.S. "The development of all the hydropower potential at existing hydropower and non-hydropower dams could generate almost 160 billion kilowatt-hours of electricity and save 727,000 barrels of oil per day," the report stated. "This is seven and one-half times the savings associated with the President's goal of solar heating 2.5 million homes by 1985."

Because "front end" money spent to determine the merits of moving forward on a project is frequently the most difficult for a public agency to obtain, the program of loans for feasibility studies and applications for regulatory approvals authorized under Section 402 of the Public Utility Regulatory Policies Act of 1978 is deemed by many local publicly owned utilities to be of special importance. The ten-year repayment and the "forgiveness" features in the event that a project proves technically or economically infeasible are a definite encouragement to consumer-owned utilities to seek to use this form of renewable solar energy. This program should be continued.

EXHIBIT F

VARIATIONS AMONG UTILITIES REQUIRE DIFFERENT SOLUTIONS

It is important to isolate those utilities that are having exceptional financial difficulty from those that are not. Only in this way can we get down to the real causes of such difficulty and determine if it lies within the scope of the Federal government's powers to deal with such causes.

For those companies that may be in serious financial trouble, the regulatory commissions have an obligation to make two determinations: (1) Is the financial trouble traceable to mismanagement; and (2) Is there evidence that a change in commission policies and procedures could produce significantly better financial health for these utilities?

This does not mean to suggest that only poorly managed companies are apt to find themselves in financial trouble in today's environment. There have been some external shocks to the economic system that could have brought very capable managers to grief. A great deal depends upon the particular financial posture a utility found itself in when the shocks occurred. A utility caught in the middle of a large expansion of its generating capacity at the time that electric load growth stalled, and then faltered forward in the mid-seventies, had very few easy options. Nevertheless, an examination of the quality of management is a reasonable test for application to a utility which seeks regulatory relief of its financial distress. Has the financially troubled utility engaged in anti-competitive action to reduce the opportunities for the utility's wholesale customers and competitiors to take on more of the power supply responsibility? What power supply alternatives has the financially troubled utility engage in? Has it attempted to sell off excess capacity to other entities? Has it attempted to purchase capacity from systems with excess capacity as an alternative to new construction? Has it instituted programs of power exchanges to improve sales and purchases of low cost economy energy? Does it have a load management program to improve system load factor?

In short, an intensive management audit should be routine prior to any consideration of special regulatory relief.

In April, 1973, the Federal Power Commission (the predecessor of the Federal Energy Regulatory Commission) published "Performance Profiles", a company-by-company examination of the country's private power companies for the period 1963-1970. The FPC stated of the 278-page study that:

> *"This report presents a comprehensive array of analytical statistics on the economic characteristics and cost performance of private electric utility companies in the United States for the years 1963-1970. The data are organized in a convenient format permitting detailed inter-company comparisons as well as analyses of year-to-year changes for the more than 200 companies covered by the report. The coverage of the data includes various statistical indicators for identifying the special circumstances which set one company apart from the others and often help to explain differences in the comparative operating results for particular companies."*

An updated version of this report would be of considerable value in determining the absolute and relative financial position of the nation's investor owned electric utilities.

On the basis of existing information, we know that there are significant differences among privately owned electric utilities and also between those companies and other industrial concerns.

For instance, Forbes' 33rd "Annual Report on American Industry" published in January, 1980, showed electric utilities had a median net profit margin of 10.1 percent for the last 12 months. The range of medians for the covered companies was from a low of 1.9 percent to a high of 20.6 percent -- a tenfold difference. The overall utility median net profit of 10.1 percent compared with 5 percent for all industries. In other words, utilities had twice as many dollars available for payment of dividends and reinvestment in the business as did the other covered industries. These other non-utility industries did not have the benefit of certain governmental powers (ability to condemn property), protection from head-to-head competition (by franchises and territorial agreements), and a set of captive customers.

The differences among private power companies also shows up in the diversification of their investments and the sources of their income.

Investor-owned electric utilities have entered a large number of non-power functions, including oil exploration, mining, communications, electronics, transportation, frozen foods, hotels, shopping centers, and land speculation. Some examples:

Montana Power Company gets 44 percent of its total earnings from sources other than electric power, mainly coal and gas.

Coal and telephones provided 51 percent of Pacific Power and Light Company's total operating income in 1979, and the company has said it is thinking of going into the cable television business. Diversification can make good use of excess tax credits generated by PP&L's electricity-producing side, the company claims.

"State regulators are becoming increasingly fearful that diversification will distract utility management attention from its primary business," Business Week reported in its February 23 issue.

A former head of Oregon's Public Utility Commission, Charles Davis, noted in 1979 that the rate-setting process largely insulates management of regulated utilities from responsibility for decisions. Consumers have a very limited ability to go elsewhere for energy, and the commission is required by law to ensure that the utilities have rates adequate to keep them in business, he pointed out. "When unregulated industries have problems, people in upper management are released," Davis said. "It's a refreshing process for an enterprise, and it's too bad regulated utilities never have to take that bath."

Figures published by the Department of Energy's Energy Information Administration show that in 1979 local public power systems had lower expenses than private power companies for production, distribution, administrative and general costs, accounting and collections, customer service, and information and sales. These lower expenses helped local public power systems keep down the cost of electricity to their consumers compared to the prices charged by private power companies to their customers. Average residential revenue for the companies in 1979 was 4.64¢ per kilowatt-hour -- 44.1 percent higher than the public systems' average of 3.22¢ per kilowatt-hour. Average commercial and industrial revenue per kilowatt-hour for the private power companies in 1979, 3.66¢ per kilowatt-hour, was 27.1 percent higher than the 2.88¢ per kilowatt-hour for public power systems.

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